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2022 Coal Plants Retirement Study Report

Dominion Energy South Carolina, Inc.

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CRA Project No. D34444

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1. Executive Summary

Dominion Energy South Carolina, Inc. ("DESC" or the "Company") is dedicated to the delivery of safe, reliable and affordable energy to its approximately 771,000 customers in South Carolina. It is committed to doing so through a utility system that creates a sustainable energy future and a cleaner environment for the state. Ending reliance on coal as a fuel source for electric generation as soon as is reasonable and practical is key to DESC's commitment. Since 2002, DESC has closed or repowered eight of its twelve coal units, and has reduced the percentage of coal-based energy it uses to serve its customers from 66% in 2005 to 23% in 2019.

DESC's Commitment to Retire Coal:
In its 2020 Integrated Resource Plan ("IRP"), DESC included in its modeling a resource plan that would retire the Wateree Station ("Wateree") and A. M. Williams Station ("Williams") coal units in 2028. Wateree and Williams are the last three last coal-only units on DESC's system. In its pre-filed testimony in the 2020 IRP proceeding, DESC announced it would undertake a study to determine the costs, schedules and reliability impacts of retiring Wateree and Williams early. This report represents a comprehensive coal plant retirement study which is the initial phase of many that result in replacement resources. As a result of the analysis conducted to prepare this study, DESC's current goal is to end reliance on coal as a fuel source by 2030 assuming that goal can be achieved consistent with maintaining reliable and reasonably priced service to its customers.

Stakeholders: Throughout the process of planning for these retirements, DESC has engaged the IRP Stakeholder Advisory Group (the "Stakeholders")[1] to provide input on retirement and replacement options, market scenarios, and inputs used in modeling costs and impacts. Details regarding the Stakeholder processes are provided in Section 5.2.

Transmission Impact and Reliability: In support of this Coal Plants Retirement Study (the "Retirement Study" or the "Study"), DESC's Electric Transmission Planning Department performed a Transmission Impact Analysis ("TIA") to provide an initial assessment of the transmission system upgrades required under five representative retirement and replacement options. The TIA determined that under each of these options DESC will need to construct significant transmission system upgrades to maintain system reliability. The most complex and expensive transmission upgrades are those required to support retiring Williams. The transmission upgrades to support retirement of Wateree are less extensive.

Replacement Schedule and Feasibility Conclusions: Based on information provided in the TIA, DESC determined that retiring Wateree by 2028[2] is a reasonable planning goal, but will require an estimated 344 MW of replacement capacity to maintain system reliability. Retiring Wateree and Williams by this date allows DESC to avoid significant elements of compliance costs associated with the Environmental Protection Agency's ("EPA's") current Steam Electric Power Effluent Limitation Guidelines ("ELGs"). However, considering the complexity of the transmission and fuel supply projects required to replace Williams, and the time required to permit, site and construct those projects, the earliest feasible retirement date for that unit is

[1] The Stakeholders who have participated in the process are listed in note 7, below.

[2] The retirement goal for the Wateree units is December 31, 2028, and is referred in this study as 2028. Under other planning conventions, a December retirement date is reported as having occurred in the following year, *i.e.,* 2029 for Wateree. For consistency, this report references the actual year of retirement even if the retirement occurs on the last day of that year.

2030.[3] Both projected dates assume that the regulatory and legal processes required to authorize, site and construct the replacement generation and supporting transmission and gas supply infrastructure are not unduly delayed.

Least Cost Transmission Options Based on the TIA: The TIA determined that of the five retirement and replacement options studied, the least expensive from a transmission standpoint involves gas-fired generation located forty miles north of Charleston, South Carolina at the site of DESC's retired Canadys Station site ("Canadys") in Colleton County, SC. The TIA indicated that the transmission projects needed to create a path to import permanent replacement power from neighboring utilities would be extensive and time consuming even under the optimistic assumption that long-term, reasonably-priced, low-carbon power supplies were available to import.

Cost to Customers of Retiring and Replacing the Units: Retiring Wateree in 2028 provides clear cost benefits to customers assuming that adequate replacement generation can be obtained and the retirement can be accomplished in time to avoid the ELG investments required to keep the plant operating after 2028. Under most market scenarios, retiring both Wateree and Williams early, in 2028 and 2030 respectively, would result in a small increase in costs while materially reducing carbon emissions. Specifically, assuming Wateree is retired in 2028, retiring Williams in 2030 would increase the compound annual growth rate in a typical residential customer's bill by 0.34% or less compared to waiting to retire Williams until its optimized retirement date which can be as late as 2047 under some market scenarios.

CO_2 Impacts of Retiring and Replacing the Units: By retiring coal plants and adding solar and natural-gas fired generation, DESC has reduced its CO_2 emissions from 2005 to 2022 by approximately 37% while fully offsetting the carbon impacts of growing customer loads. Retiring Wateree by the end of 2028 and Williams by the end of 2030 will reduce 2040 CO_2 emissions on average by an additional 14% compared to operating all Units until the end of their useful lives. This will increase DESC's estimated carbon reduction levels (2005 to 2040) from 49% to 63% on average across all market scenarios, with reductions as high as 67% in certain market scenarios. On average retiring each plant early adds a 7% reduction in 2040 carbon emissions compared to 2005 levels.

Available Resource Options: This Study is not intended to identify the specific replacement generation resources for Wateree and Williams. The scenarios, assumptions, and modeling results of the TIA and this Study will not limit the replacement resources that are available for DESC to model or select as a preferred retirement and replacement plan in the 2023 IRP. Actual replacement resources will be determined in consultation with Stakeholders, through future competitive procurement activities and subject to regulatory approvals including the Siting Act proceedings and future IRPs. Among other assumptions, DESC intends to model a low carbon generation replacement portfolio in its 2023 IRP analyses. Doing so will require the inclusion of advanced non-emitting technologies like small modular nuclear reactors or hydrogen powered generation among the IRP candidate resources in future IRPs.

Roles and Responsibilities: Charles River Associates ("CRA") was retained by DESC to help guide and review the analysis in the Retirement Study, support stakeholder engagement, and evaluate the local economic impacts of early coal retirement described below in Section 10.

[3] The retirement goal for the Williams unit is December 31, 2030, and is referred in this study as 2030. Under other planning conventions, a December retirement date is reported as having occurred in the following year, *i.e.,* 2031 for Williams. For consistency, this report references the actual year of retirement even if the retirement occurs on the last day of that year.

CRA was chosen based on its experience in managing coal retirement evaluations for other utilities and its existing role in facilitating the IRP Stakeholders process. DESC was responsible for the portfolio and system modeling to evaluate different retirement options. The conclusions of this study are DESC's conclusions.

Economic Impact Analysis: The retirement of a coal plant can result in economic impacts associated with the plant closure, decommissioning, and the development of replacement capacity. CRA conducted a study to evaluate and quantify the county- and state-level economic impacts of retiring the Williams and Wateree plants. The study was based on data collected from DESC on the employment and categorized expenditures of each plant, including property taxes, and publicly available sources. CRA quantified the direct, indirect, and induced economic impacts using the IMPLAN input-output model. The analysis did not make any assumptions about the level of plant employee retention or plant suppliers finding new customers for goods and services – both of which are likely outcomes based on DESC's commitment to its employees and recent experience with power plant closures. CRA found that the economic impacts are greatest in the counties where the plants are located, but that none of the counties in the study area would see an impact greater than about 0.5% of its workforce or 0.2% of its regional GDP. The study and results are presented in Section 10 of this report.

Summary of Conclusions: The Study supports several high-level conclusions which DESC will continue to evaluate and develop and use to inform modeling in the 2022 IRP Update and the 2023 IRP:

(1) Retiring Wateree at the end of 2028 could benefit customers under most market conditions but is subject to schedule risks and uncertainties concerning replacement capacity.

(2) DESC can plan to avoid the cost of complying with current ELG requirements at Wateree, but doing so creates the risk that Wateree would have to be retired from service even if replacement capacity was not yet in place.

(3) Retiring Williams is not reasonably feasible before 2030 in light of the complexity of selecting and siting replacement resources including electric transmission and fuel supply. Even if Williams is retired early, DESC needs to plan to comply with the ELG requirements for Williams and make ELG capital investments over the next three years using the least-cost approach to compliance.

(4) Setting 2030 as the earliest feasible retirement date for Williams is appropriate as a "best case" planning goal subject to risk and uncertainty. It includes little if any buffer to accommodate regulatory or construction delays or legal challenges to permitting and siting. It is subject to review and revision as retirement planning continues.

(5) Retiring Williams in 2030 reduces CO_2 emissions at an additional cost to customers that is minimal when annualized over 30 years. Early retirement of Williams could expose customers to higher costs and risks if there are delays in the critical paths for replacement generation.

The conclusions of the Study will guide future retirement planning and IRP proceedings. They will be subject to on-going review and modification as additional information and analysis becomes available.

2. Role and Purpose of the Study

The purpose of this Study is to inform the Stakeholders and the Public Service Commission of South Carolina (the "Commission") about the timeline and steps that need to be taken to retire Wateree and Williams. The results of this Study and subsequent analysis will inform the inputs to DESC's 2023 IRP.

In the coming months, DESC will refine its analysis based on information including:

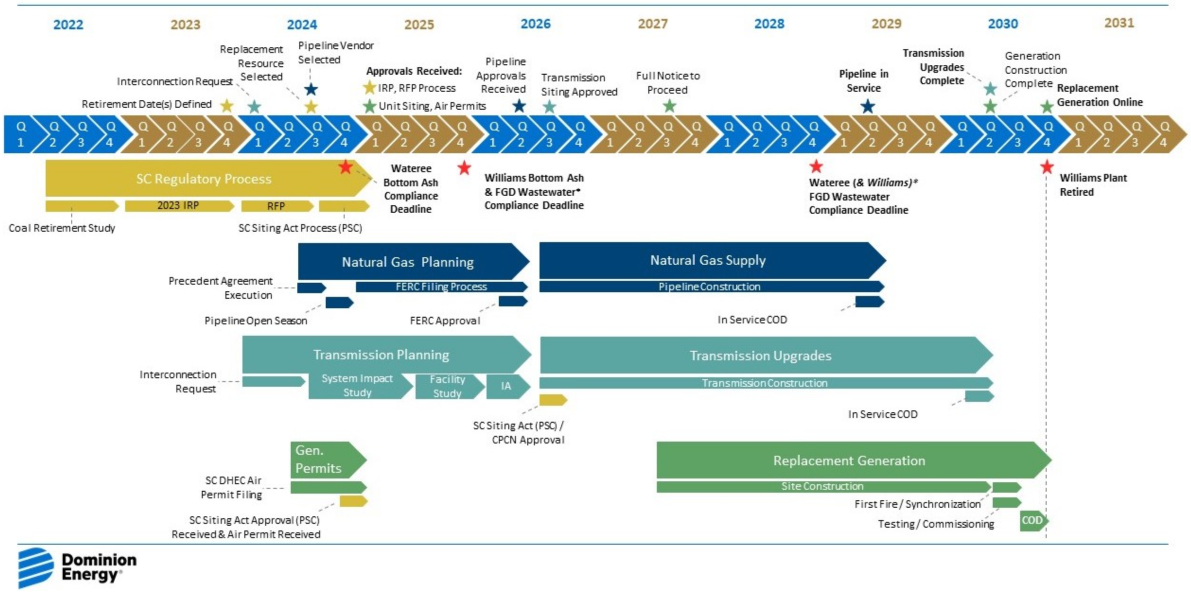
1. Inputs from ongoing Stakeholder consultations and suggestions;
2. Forthcoming TIA scenarios being requested by DESC reflecting Stakeholder feedback and continued analysis of the conclusions of this Study;
3. Market information generated by forthcoming indicative and binding request for proposals ("RFPs") concerning replacement generation resources;
4. Refinements to its PLEXOS modeling inputs to reflect changing market conditions as specified by the Commission; and
5. Information from natural gas suppliers concerning the expected cost and timeline for securing any additional pipeline capacity needed to support additional generation as required to maintain system reliability given the available replacement options.

In light of this information, and in consultation with Stakeholders, DESC will review a broad range of retirement and replacement options to select a preferred path forward for Commission approval through its 2023 IRP proceeding.

3. The Path to Retirement

To retire Wateree in 2028 and Williams in 2030 will require DESC to complete a complex and interrelated series of planning, regulatory and construction activities on a compressed timetable. Many aspects of this timetable are subject to regulatory review and approval processes with timelines that are outside of DESC's direct control and are subject to significant schedule risks. This sequence is illustrated in **Figure 1**, the Williams and Wateree Illustrative Planning Schedule, which assumes that a permanent replacement for both Williams and Wateree capacity is procured in a single project that involves procuring additional natural gas supplies. This schedule is intended to be illustrative of the retirement and replacement process and will require further refinement as additional planning and analysis is complete.

Figure 1: Williams and Wateree Illustrative Planning Schedule



3.1. Interim Capacity to Replace Wateree

Retiring Wateree in 2028 will create an immediate 344 MW shortfall in DESC's ability to meet seasonal reserve requirements. DESC could meet this shortfall in either of two ways. It could procure a permanent replacement for the Wateree capacity on a standalone basis by 2029. Or it could obtain interim resources to cover the Wateree deficit beginning in 2029 and provide permanent capacity to replace Wateree as part of the procurement of capacity to replace Williams.

Off-system capacity purchases are a potential option for meeting the capacity shortfall for Wateree on an interim basis. However, the regional market for capacity is constrained by the planned retirement of coal units by Southern Company, Santee Cooper, and the Duke companies. Competition for off-system capacity resources will be high. In addition, DESC has limited existing ability to import power from adjacent systems during peak period. Even on a relatively short-term basis, firm off-system purchases at this level will likely require DESC to expand its interconnection capacity with neighboring utilities to allow the purchased power to be delivered onto its system. Interconnection expansion projects involve schedule risks due to potential regulatory delays in permitting and siting which are largely beyond DESC's control.

Alternatively, DESC may need to construct a modest and carefully chosen set of on-system resources to support retiring Wateree by the end of 2028. Given the more limited role Wateree plays in maintaining system reliability, and the greater availability of natural gas supplies in the northern part of its system, DESC believes that procuring resources to replace Wateree alone would likely be less complex and time consuming than procuring those needed to replace Williams. However, schedule risks would still be involved in the Wateree replacement, including the potential for permitting and siting delays. DESC will continue to monitor both the opportunities and risks involved in replacing Wateree as planning proceeds toward the selection of a preferred replacement plan to be presented in the 2023 IRP. DESC will present a more definitive plan and schedule at that time.

3.2. Permanent Capacity to Replace Williams and Wateree

DESC has not selected the preferred location and technology for permanent replacement capacity for Wateree and Williams. However, for the purposes of this Study, DESC has assumed that the required replacement portfolio will include an important component of new natural gas-fired generation. DESC has done so because apart from natural gas fired generation there are few, if any, dispatchable generation resources that today are economically viable and technologically practical to replace the role of existing coal units in supporting system reliability. In addition, DESC's obligation to reliably service its customers prohibit it from planning for unproven technology to mature and become economical on the early retirement timeline evaluated in this Retirement Study. Accordingly, the Study assumes that the schedule for replacing the Williams and Wateree generation will require natural gas pipeline expansion projects. DESC will continue to monitor the validity of these study results as planning proceeds toward the 2023 IRP.

The current Illustrative Planning Schedule in **Figure 1** includes the following assumptions as to key milestones:

- By the end of the fourth quarter of 2023, DESC assumes that regulatory review and approval of its 2023 IRP will be complete, and it will define target retirement dates and replacement resource requirements for Wateree and Williams. DESC will then issue RFPs for the required resources. The DESC 2023 IRP will be filed by February 28, 2023 and by statute, the Commission has 300 days to rule on the IRP. If this IRP is not approved within these dates, the Illustrative Planning Schedule will be negatively impacted.

- Early in the first quarter of 2024, DESC anticipates requesting a Large Generator Interconnection Study to identify the required transmission upgrades to accommodate any self-built resources it proposes as replacement resources for Wateree and Williams. The DESC Transmission Planning Department may be able to study all proposed or selected projects in a single cluster under the new Resource Solicitation Cluster process if the Commission adopts that Interconnection Study method. If the Commission does not, the Illustrative Planning Schedule will be negatively impacted.

- Under the Illustrative Planning Schedule, DESC will select the replacement resources from an all-source RFP and will file for all required Siting Act certifications and air emissions permits in the second quarter of 2024 for self-built resources that result from the RFP. The schedule assumes that the Commission and the South Carolina Department of Health and Environmental Control ("DHEC") issue all required permits for new generation by the end of 2024.

- The Illustrative Planning Schedule assumes that, at the conclusion of a competitive RFP for any new natural gas supplies, DESC will execute a precedent agreement for required natural gas supplies resulting in a pipeline open season, followed by planning of the required natural gas pipeline expansions or extensions by the selected vendors, and their filing for required Federal Energy Regulatory Commission ("FERC") permits in the third quarter of 2024. The Illustrative Planning Schedule assumes that pipeline construction will begin in the third quarter of 2026 and be completed by the second quarter of 2029.

- The Illustrative Planning Schedule assumes that transmission planning is completed in the second quarter of 2026. This is followed by design and engineering of the required assets, RFPs for their construction, Siting Act approvals and environmental permitting, and procurement of rights of way and other land use entitlements after appropriate public outreach. Transmission construction is assumed to begin in the third quarter of 2026 and be completed by the second quarter of 2030.

- The Illustrative Planning Schedule assumes that design, engineering, and equipment and construction procurement for replacement generation is completed in the third quarter of 2027 with full notice to proceed given to the selected vendors at that time. Site construction is assumed to be completed during the second quarter of 2030 with testing and commissioning to be completed by the end of 2030.

DESC will work diligently to achieve the retirement of Williams and Wateree as early as reasonably practical consistent with reliability and affordability of its electric service. However, early retirement according to the Illustrative Planning Schedule will involve multiple construction and regulatory risks that are outside of DESC's control. Both retirement dates for Wateree and Williams assume that the regulatory and legal processes required to authorize, site and construct the required assets are not unduly delayed by outside parties or otherwise. The greatest risk appears at present to be the risk associated with the permitting and construction of required natural gas pipeline capacity by the appropriate FERC-regulated interstate pipeline companies, a process which is ultimately outside of DESC's control and the control of South Carolina regulators. These projects are an important driver of the overall retirement schedule and an important risk factor associated with retiring Williams and Wateree early.

4. Introduction to Retirement Study

4.1. Purpose, Scope and Approach

In pre-filed testimony in its 2020 IRP proceeding, DESC committed to conducting a study to analyze the likely costs, reductions in carbon emissions, and economic impacts from the potential early retirement of its Williams and Wateree coal units (together, the "Units")[4] which are the last three units remaining on DESC's system that burn only coal. In DESC's proposed Short Term Action Plan, filed as an exhibit in that proceeding, DESC presented a timeline and more formal statement of the scope of that study for consideration by the Commission.[5] In Order No. 2020-832, the Commission ordered DESC to complete that study to "inform development of its 2022 IRP Update and its 2023 IRP and to solicit parties' recommendations on guidelines for performing this analysis through the ongoing IRP Stakeholder Process." Order 2020-832, at p. 17. On June 6, 2021, the Commission opened Docket No. 2021-192-E "so that the company and other parties could advise the Commission on an appropriate procedural schedule along with any statutory or regulatory deadlines that might need to be addressed." On April 28, 2022, the Commission clarified the purpose of Docket No. 2021-192-E is "to develop a procedural schedule including the data, methodologies, analysis and next steps for considering coal plant retirement within the framework of future IRPs via the 2020 IRP

[4] See the Prefiled Rebuttal Testimony of DESC's Witness Eric Bell, in Docket No. 2019-226-E, filed on August 28, 2020 at page 23.

[5] See Late Filed Exhibit 17, filed on October 29, 2020, in Docket No. 2019-226-E.

Docket 2019-226-E and Order No. 2020-832, including any statutory or regulatory deadlines that may need to be addressed."

Accordingly, this Study evaluates potential timing and dates for the early retirements of the Units and the impact on system reliability, customer costs, carbon emissions, and local jobs and economies under multiple retirement options. To inform this analysis, DESC's Transmission Planning Department completed a TIA[6] to provide initial estimates of the transmission costs and construction schedules necessary to support grid reliability under five representative retirement and replacement cases (the "TIA Cases"). DESC selected the TIA Cases after consultation with Stakeholders[7] to define a reasonable range of transmission-related costs and associated construction schedules for initial evaluation.

With the results of that evaluation, DESC then used the resource optimization functions of its PLEXOS modeling software to determine optimum retirement dates for the Units, and to optimize resource portfolios to replace the capacity and energy that the Units supply to the grid. DESC conducted this evaluation by modeling the impact of five retirement options or sets of options (the "Retirement Options" or "RO") representing a range of potential retirement dates for the Units, including retirement dates selected by the PLEXOS optimization model. DESC modeled these Retirement Options under five different market and regulatory assumptions (the "Market Scenarios") incorporating integrated assumptions regarding fuel costs, carbon costs, and load growth.

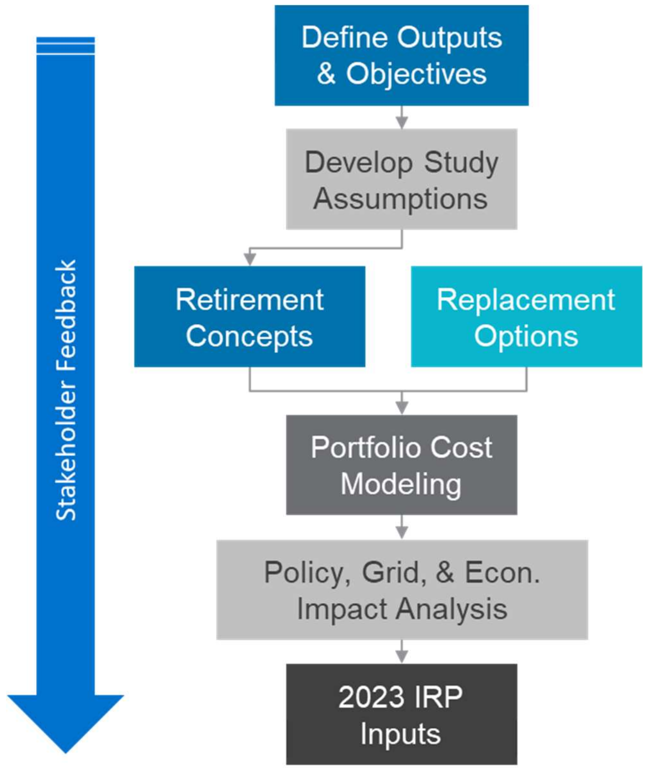
Both the Retirement Options and the Market Scenarios were developed after thorough consultation with Stakeholders as to assumptions and inputs. The result was a forecast of the costs and CO_2 emissions for DESC's electric system for each of the five Retirement Options under each of the five Market Scenarios.

This process is illustrated below in **Figure 2**.

[6] The TIA was filed with the Commission in in Docket No. 2019-192-E on January 7, 2022.

[7] Regular participants in the IRP Stakeholder Advisory Group includes representatives of the South Carolina Office of Regulatory Staff ("ORS"), the South Carolina Energy Office, Carolinas Clean Energy Business Association, CMC Steel South Carolina, Sierra Club, SC Coastal Conservation League, Southern Alliance for Clean Energy and BrightNight, LLC. The initial invitees also included the SC Small Business Chamber of Commerce, SC Office of Economic Opportunity, SC Energy Users Committee, SC Community Action Partnership, Johnson Development Associates, Inc., South Carolina Solar Business Alliance, AARP South Carolina, and Walmart, Inc. Meetings are open and other interested parties may attend.

Figure 2: Overview of the Retirement Study Process



Throughout the formulation of this Study, DESC engaged the Stakeholders to review the methodology, inputs and modeling results. In recognition of the overlap of interested parties and modeling issues to be evaluated, DESC has conducted this Stakeholder process using the existing IRP Stakeholders Advisory Group. DESC retained CRA to facilitate the Stakeholder process and serve as project manager for the Study.

CRA structured Stakeholder meetings to allow participants ample opportunities to raise questions, challenge assumption, and contribute their insights. CRA and DESC have used input gained to guide DESC's evaluation of early coal retirements in important respects.

4.2. Evaluation Framework

Establishing the optimal strategy for retiring coal units involves assessing the impacts of retirements on electricity costs and carbon emissions under a range of possible retirement and replacement options and future market conditions. The factors that must be considered related to the retirements themselves include the impact on reliability of the utility's transmission and generation system, the cost and carbon emissions of capacity resources that will replace the retired coal units, and the time it will take to permit, procure and construct the necessary transmission upgrades and capacity replacements. In addition, the evaluation must consider these impacts under a range of future market conditions related to fuel prices, load growth and carbon regulations. From these, DESC can measure the potential range of impacts on the cost of electricity to customers, and on the economic health of local communities and the state.

In consideration of these requirements, DESC organized the Study across three elements: Transmission Reliability, Cost of Electricity and Carbon Emissions, and Local Jobs and Economic Impacts.

Transmission Reliability

DESC's Transmission Planning Department conducted a TIA to evaluate the system impact of retiring one or all Units by the end of 2028 under five early retirement and replacement scenarios reflecting different combinations of replacement resources located at strategically selected locations on DESC's system. The TIA's findings are discussed in more detail in Section 6 of this report. These cases were limited in order to expedite analysis, and DESC expects to request additional TIAs, and ultimately Large Generator Interconnection Studies, as more definitive retirement and replacement plans are developed.

Cost of Electricity to Customers and Carbon Emissions

DESC used the resource optimization capabilities of its PLEXOS system planning model to assess changes in the cost of electric service to customers and carbon emissions under the five Retirement Options. DESC evaluated these Retirement Options under the five Market Scenarios that reflect possible scenarios for changes in gas prices, load growth and carbon emission costs. The Retirement Options and Market Scenarios were chosen in consultation with Stakeholders. All told, DESC modeled costs and carbon emissions under twenty-five combinations of Retirement Options and Market Scenarios. The results are described in Section 8 of this report and details concerning the modeling inputs and assumptions used in the analysis are discussed in more detail in Section 9.

Local Jobs and Economic Impacts

DESC estimated the potential direct employment impact of plant retirements and retained CRA to estimate the broader economic impacts. CRA evaluated the tax, employment, and local productivity impacts of plant retirement and decommissioning activities at the state and county level. These impacts are discussed in more detail in Section 10 of this report.

5. Background

5.1. DESC's Current Generation Portfolio

DESC currently operates an integrated electric utility system that serves approximately 771,000 customers in 24 counties in central, southern and southwestern South Carolina. DESC's service territory covers approximately 16,000 square miles and includes the metropolitan areas of Charleston, Columbia, Beaufort, and Aiken and many other smaller cities and towns and rural areas in South Carolina. In 2021, DESC's customer base included 664,550 residential customers, 101,505 commercial customers, 763 industrial customers, 1,042 public street lighting customers and 3,751 other public authority customers. The municipal electric cities of Winnsboro and Orangeburg are also wholesale customers.

Since 2011, DESC has added 107,341 net additional electric customers, an increase of 16.2%, with growth in the residential class representing 94,156 of these new customers. Growth in customer count has been concentrated in coastal areas and the Columbia areas as shown in **Table 1**, below.

Table 1: DESC Customer Growth by Representative Districts

REGIONS	Customers 12/31/2011	Customers 12/31/2021	Totals
LEXINGTON/CHAPIN	47,068	58,424	35.83%
LOW COUNTRY	80,583	95,509	18.52%
METRO CHARLESTON	194,495	233,349	19.98%
METRO COLUMBIA	191,156	212,633	11.24%
SOUTHERN (Beaufort, Bluffton, Walterboro, Hardeeville)	73,510	886,736	17.99%
WESTERN (Aiken, North Augusta, Barnwell, Edgefield)	77,460	84,962	9.68%

To support this growing customer base, DESC currently operates 64 hydro and fossil generating facilities with a dependable net winter generating capacity of 5,255 MW and a single unit nuclear station with a net dependable winter generating capacity of 653 MW. These resources are supplemented by 973 MW of solar generation purchased from third parties under long-term power purchase agreements ("PPAs") and an additional 130 MW of customer scale solar. By March of 2023 DESC will add 136 MW of solar generation and 34 MW of battery energy storage system ("BESS") associated with solar generation. DESC also benefits from a 20 MW allocation of power from the Southeastern Power Administration, which operates hydro resources on the upper Savannah River.

Of the fossil generating facilities, DESC has four existing coal units: Wateree, which is a two-unit 684 MW coal station; Williams, which is a single-unit 610 MW coal station; and Cope Station, a single-unit 415 MW coal station. The Cope unit is dual fuel capable (coal and/or natural gas). It operates on interruptible natural gas when natural gas is available at prices that provide energy at a lower fuel cost than coal. Cope Station does not have firm gas transmission assigned to the plant and firm transportation is not currently available.

Wateree is the largest coal-fired generation station on DESC's system and is located in lower Richland County, approximately 20 miles from the City of Columbia in a part of DESC's transmission system that is well supported by existing generation resources. Approximately 3,500 MWs of DESC's generation capacity is located in the Columbia area or adjacent counties and Wateree represents only approximately 20% of that capacity. This fact and the relative accessibility of natural gas supply resources in DESC's northern and the adjacent western districts will make replacing Wateree less challenging than Williams.

Williams is located in Goose Creek, South Carolina, approximately 25 miles north of Charleston, South Carolina in the Bushy Park industrial area where it supports several of DESC's largest and fastest growing load centers. Because of limited natural gas pipeline capacity and rail service, and constrained land use patterns in the area, only 804 MWs of DESC's generation capacity is located in the Charleston area. Williams represents 76% of that capacity. Under present operating conditions, maintaining reliable service to the Charleston area is challenging when Williams is off line for maintenance or otherwise unavailable.

For these reasons, it is highly likely that the retirement of Williams will require additional dispatchable, long-duration generation resources to be sited in the southern transmission district. This poses a challenge for retirement planning because there are few alternatives to natural gas generation currently available that can replace the dispatchable generating capacity that Williams supplies to the Charleston area and that area currently lacks the high-volume natural gas pipeline infrastructure needed to support a new large natural gas-fired generation facility. This is likely to be an important constraint affecting both the costs and timeline for retiring Williams.

In addition, in the South Carolina Low Country, which includes the Charleston area, DESC's transmission and generation system is extensively interconnected with that of the South Carolina Public Service Authority ("SCPSA" or "Santee Cooper"). Generation supply in the Low Country is becoming increasingly constrained due in part to Santee Cooper's plan to retire several coal-fired generation units serving the region. Santee Cooper has announced plans to retire the four-unit Winyah coal-generation plant (1,150 MW) located near Georgetown, South Carolina and its long-term goal of retiring some or all of its four-unit Cross coal-fired generation plant (2,375 MW) in Berkeley County, South Carolina. These retirements will have a significant impact on the reliability of DESC's transmission grid and electric service to the Charleston area if Williams is retired.

5.2. Stakeholder Engagement

CRA designed the Stakeholder process to further the Commission's goals of increasing transparency, reducing misunderstanding, and improving the quality of the coal retirement planning process. During the first Stakeholder session, CRA presented the following protocols to ensure that all Stakeholders could be heard and their concerns addressed in the process. The protocols provide that:

- Stakeholders drive the agenda by suggesting and prioritizing topics for analysis and presentation in future Stakeholder sessions;
- CRA solicits comments, questions, and feedback from Stakeholders during and between meetings and documents them in writing;
- CRA assigns "homework" at the close of each session to ensure that Stakeholders follow up on the issues, suggestions and positions raised in each session;
- Stakeholders submit additional questions, suggestions, and feedback in writing via the group website; and
- DESC and CRA document a response in writing to each Stakeholder's questions, suggestions, and feedback as documented by CRA.

In preparing the TIA and this Study, CRA and DESC met with Stakeholders six times with sufficient time between the meetings to allow for a meaningful response by CRA and DESC to prioritize topics identified by the Stakeholders. This Stakeholder timeline for the Retirement Study is illustrated in **Figure 3** below.

Figure 3: Retirement Study Stakeholder Process Timeline

The process has worked as CRA intended to ensure significant and well-documented Stakeholder engagement. A summary of questions, suggestions, and feedback from each Stakeholder session along with the written response can be found in **Appendix C** of this report.

6. The Transmission Impact Analysis

6.1. Overview of the TIA Study

DESC began the coal retirement planning process by asking its Transmission Planning Department to assess the transmission upgrades that would be needed to allow the grid to continue to reliably serve customers after retirement of the Units. Through consultation with Stakeholders, DESC arrived at the five TIA Cases to encompass a range of potential retirement and replacement scenarios for retiring both Williams and Wateree by 2028. On April 6, 2021[8] and again on May 13, 2021,[9] DESC modified the TIA request to reflect suggestions made by Stakeholders. A second round of TIA requests are under consideration at this time.

The TIA, which was issued and filed with the Commission in January of 2022, identified the transmission upgrades that would be required to maintain grid reliability under the five TIA Cases and provided initial estimates of associated costs and construction schedules. DESC then used this information to conduct the resource optimization modeling which is discussed in more detail in Section 8.

The TIA was limited in order to expedite analysis of the transmission requirements for retiring both Williams and Wateree by 2028. Once additional information is known about the potential location, technology and completion schedules for replacement generation, and retirement dates for the Units, DESC's Power Generation Group will request DESC's Transmission Planning Department to prepare one or more Large Generator Interconnection Studies for the utility self-build alternatives under active consideration. These Large Generator Interconnection Studies will incorporate updated load forecasts, power flow data, and

8 https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/Modified_Transmission_Impact_Analysis_Request-DESC_Wateree_20200406.pdf

9 https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/Modified_Transmission_Impact_Analysis_Request-DESC_Wateree_and_Williams_20210513_FINAL.pdf

construction costs as they exist at the time of the studies. In addition, the power flow models on which TIAs and Generator Interconnection Studies are based are continuously updated to include all planned transmission system upgrades, and all generator interconnection requests with an executed and active Interconnection Agreement, whether on DESC's system or on neighboring utilities. The results of future interconnection analyses will reflect changes in all of these inputs.

6.2. The Five TIA Cases

The five TIA Cases analyzed in the TIA were:

1. Retire Wateree in 2025. Add a 200 MW battery BESS and 200 MW PV solar generation ("Photovoltaic Solar") at the Wateree site, and contract for 200 MW off-system purchased power beginning late in 2025. Retire Williams in 2028 and add a 534 MW 1X1 CC ("Combined Cycle") at the site of the Jasper Combined Cycle Generating Station in Jasper County, SC ("Jasper") and add a 200MW ESS and 200 MW PV solar generation at Canadys.
2. Retire both Wateree and Williams in 2028. Build a 534 MW 1X1 CC and a pair of frame-built CT's ("Combustion Turbines") totaling 523 MW at Jasper.
3. Retire both Wateree and Williams in 2028. Build a 534 MW 1X1 CC and a pair of frame-built CT's totaling 523 MW at Canadys.
4. Retire both Wateree and Williams in 2028. Build a 534 MW 1X1 CC at Canadys. Add a 200 MW ESS and 200 MW PV solar generation at Wateree, and contract for 400 MW off-system purchases ("PPA") from the Southern Company interface ("SOCO") on the Georgia-South Carolina border.
5. Retire both Wateree and Williams in 2028. Enter a ten-year PPA for 1,100 MW of off-system capacity-backed energy on a firm path from the SOCO interface or the SOCO and Duke Energy Carolinas and Duke Energy Progress ("DUKE") interfaces.

The five TIA Cases represent various combinations of available electric generation technologies (PV solar, solar plus storage, off-system purchases, and natural gas-fired generation resources), and a range of locations for interconnecting generation assets to the transmission grid or receiving replacement power onto the grid. Four cases envision adding new generation assets on the DESC system (as opposed to making off-system purchases only). In those cases, DESC has assumed that it will locate the new resources at the sites of existing or retired generation units (Jasper, Canadys or Wateree) where robust existing transmission assets will reduce the cost of interconnection and reduce the cost of early retirements.

The five TIA Cases are not prescriptive. They have not limited the resource options that the PLEXOS model can call on in optimizing resource portfolios to replace the Units in the Study and future IRPs, nor will they limit the location of future resource additions.

6.3. Methodology Used in Evaluating the Five TIA Cases

DESC's Transmission Planning Department evaluated the five TIA Cases using the power flow model that DESC prepares under FERC requirements and files annually with the National Electric Reliability Council ("NERC"). This power flow model accounts for flows into, out of and through DESC's transmission system and incorporates the effects of neighboring utilities' expansion and generation retirement plans. DESC shares aspects of this model with other southeastern utilities to use in modeling interconnected power flows on their systems.

For purposes of the TIA, DESC's Transmission Planning Department specifically coordinated with neighboring utilities to quantify the impacts of their potential retirements of coal-fired generators on the regional grid. DESC's transmission systems serving the South Carolina Low Country is highly integrated with that of SCPSA. Accordingly, DESC's Transmission Planning Department collaborated with the SCPSA to jointly evaluate the five TIA Cases in conjunction with the SCPSA's comparable evaluation of the planned retirement of its Winyah generating plant in Georgetown County, South Carolina.

6.4. Findings of the TIA

Under all five TIA Cases, maintaining reliable service after Williams and Wateree are retired will require significant upgrades to the DESC transmission system. The upgrade costs for TIA Cases 1-4 are broadly similar (between $309 million and $403 million) but vary considerably in terms of the time required to construct the needed transmission improvements (estimated to be between 4 and 8 years after construction is authorized) and schedule risk related to that construction (the cases require DESC to site and build between zero and 87 miles of transmission assets on new right-of-way).

TIA Case 5 envisions replacement capacity being purchased from neighboring utilities exclusively during the standard ten-year transmission planning horizon. TIA Case 5 was the most expensive of the five cases evaluated (upgrade costs of $569 million). In addition, it had schedule risk and estimated construction time at the higher end of the range of alternatives (80 miles of new right of way, and six years of construction time).

The TIA Case 5 estimates do not include the cost of upgrades on neighboring utilities necessary to bring the additional power to the point of interconnection. Transmission resources on both sides of an interconnection with adjacent utilities are generally designed to support comparable power flows. For that reason, DESC expects that TIA Case 5 would require upgrade projects on both sides of the interconnection which would increase the cost, schedule risk and construction time for that case. For these reasons, the TIA supports the conclusion that exclusive reliance on off-system purchases as replacement capacity may not be a reasonable option for further study.

TIA Case 1 modeled the required transmission upgrade costs for Wateree and Williams separately and determined that the transmission upgrades required for the Williams retirement are much more extensive than those required for Wateree. Under TIA Case 1, two-thirds of the collective costs of the required upgrades are associated with retirement of Williams.

TIA Case 3 presented the lowest upgrade costs ($309 million) and the shortest upgrade schedule (four years compared to six years for the next shortest cases). It envisions interconnecting replacement generation resources at the site of the retired Canady's coal units which is approximately 50 miles north of Charleston and has strong interconnections to the St. George Switching Station, which is a major transmission hub serving the South Carolina Low Country.

In modeling costs for all Retirement Options considered in this Study, DESC used the transmission costs associated with TIA Case 3. This assumption reflects the lowest cost barrier to early retirements.

An overview of the five cases modelled in the TIA and their respective transmission impacts is shown in **Table 2** below.

Table 2: Summary of TIA Results

	Case 1		Case 2	Case 3	Case 4	Case 5
Year	2025[10]	2028	2028	2028	2028	2028
Retirement	Wateree	Williams	Wateree and Williams	Wateree and Williams	Wateree and Williams	Wateree and Williams
Replacement	200 MW ESS at Wateree 200 MW PV Solar at Wateree 200 MW purchase from SOCO until 2028	534 MW 1x1 CC at Jasper 200 MW ESS at Canadys 200 MW PV Solar at Canadys	534 MW 1x1 CC at Jasper 523 MW 2x0 CTs at Jasper	534 MW 1x1 CC at Canadys 523 MW 2x0 CTs at Canadys	534 MW 1x1 CC at Canadys 200 ESS at Wateree 200 MW Solar at Wateree 400 MW purchase from SOCO for 10 years	1100 MW purchase from SOCO and Duke for 10 years
Transmission Impacts						
Network Upgrade Cost	$146M	$205M	$403M	$309M	$365M	$569M
Time to Construct	Minimum of 6 years	Minimum of 6 years	Minimum of 8 years	Minimum of 4 years	Minimum of 6 years	Minimum of 6 years
New Transmission Lines	66 miles	67 miles	153 miles	133 miles	154 miles	239 miles
New Right of Way	30 miles	2 miles	87 miles	0 miles	38 miles	80 miles
New Substations	1	2	3	1	2	4

[10] See footnote 1.

7. Earliest Achievable Retirement Dates

This Study supports the conclusion that the earliest achievable retirement dates for Wateree is the end of 2028, and the end of 2030 for Williams. This is based in part on the timelines for constructing transmission resources identified by the TIA, and in part based on an assessment of the time and complexity of procuring suitable generation capacity to replace Wateree and Williams.

The TIA showed that TIA Case 3 provided the shortest path to completion of required transmission upgrades. After all approvals are in hand, those upgrades will require approximately four years to build. In addition, time must be reserved in the schedule for:

a) Completing the remaining aspects of retirement planning including determining the cost and timeline for projects to deliver gas supplies under those scenarios where it is required;

b) Completing an indicative RFP to assess the cost of replacement resources as the Commission has ordered;

c) Presenting one or more retirement options to the Commission for review and approval through the 2023 IRP process;

d) Completing RFPs and Siting Act proceedings for the generation resources required under the approved retirement options once the Commission issues a final order in the 2023 IRP docket; and

e) Completing Large Generator Interconnection Studies for the selected option(s).

Considering these requirements, and the steps that would be required to procure generation resources, December 31, 2028 is the earliest reasonably achievable retirement date for Wateree. While this retirement date is ambitious, it is consistent with the findings of TIA Case 3 and if achieved should allow DESC to avoid substantial expenses for compliance with the ELG Rule’s Flue Gas Desulfurization (“FGD”) wastewater treatment requirements. It will, however, require DESC to fill an approximately 344 MW deficit in system capacity beginning in 2029. To support this retirement date, DESC must be able to fill this capacity deficit either through a standalone procurement for permanent Wateree replacement capacity with an in-service date of 2029 or through an interim procurement with DESC obtaining permanent replacement capacity for Wateree at the same time it procures capacity to replace Williams. There are schedule risks associated with either approach as described in more detail above in Section 3.

Similarly, DESC has concluded that the end of 2030 is the earliest reasonably achievable retirement date for retiring Williams given (a) the role that Williams plays in supporting reliable service to customers in the Charleston area and Low Country as identified in the TIA, and (b) the time it is likely to take to construct transmission wetlands mitigation projects and replacement generating capacity and associated fuel supplies in that area as shown in Section 3 and **Figure 1**.

Specifically, TIA Case 3 was the only case that required less than six years of construction time to complete the required transmission upgrades. It assumed that sufficient natural gas supplies can be provided to the Canadys site or similarly located site within a four-year schedule to support new generation assets there. Any delay in providing natural gas service would delay the ability to retire Williams beyond the four-year transmission construction forecast. The TIA only estimated the time to construct replacement options and did not account for the time needed to complete remaining studies, complete any necessary RFPs, and other items listed above. For that reason, it is not a reasonable planning assumption that Williams can be replaced by December 31, 2028 in order to avoid substantial elements of ELG compliance costs there.

Based on the findings and timeline from the TIA to replace each Unit, DESC informed the PLEXOS model that the end of 2030 was the earliest achievable retirement date for Williams. This ensured that ELG costs were recognized and properly accounted for in this Retirement Study. As described in more detail in Section 8, DESC tested these early retirement dates for both Williams and Wateree through the PLEXOS model which confirmed that costs, CO_2 emissions, and impacts to retail customers justify the goal of retiring Wateree by the end of 2028 and Williams by the end of 2030.

DESC will continue to evaluate and update the assumed retirement dates for Wateree and Williams in consultation with Stakeholders and in the decision-making process leading up to the selection of a preferred retirement and replacement plan to be presented in the 2023 IRP. DESC intends to conduct a competitive RFP with interstate natural gas suppliers for the lowest reasonable cost and shortest reasonable time required to provide sufficient quantities of natural gas to the Canadys site or other suitable sites for generation assets to support reliable service to the Charleston area assuming that siting generation in that area will be required. DESC also intends to explore other options for providing required generation capacity or transmission support for the Charleston area with Stakeholders, suppliers and interconnected utilities. Further details concerning the process and timeline for replacing Wateree and Williams capacity as DESC currently understands them are described in more detail above in Section 3.

8. Modeling Costs and Benefits to Customers of Early Retirements

8.1. Summary of the Modeling Approach

DESC next performed resource optimization using Energy Exemplar's PLEXOS model to evaluate:

a) The optimal timing of retirements from a cost perspective;

b) The expected cost impact on customers from retirements; and

c) The CO_2 savings that would result from alternative retirement dates and replacement plans.

To support this modeling with input from Stakeholders, CRA/DESC prepared five narrative Market Scenarios to represent a range of potential future conditions related to fuel costs, customer load, and carbon prices. Under most Market Scenarios, the modeling optimized the retirement date for Wateree at or near the earliest possible date of 2028 but chose 2031 in just one scenario. It optimized the Williams retirement dates between 2031 to 2047, but the cost differences when averaged over the 30 year planning horizon were minimal compared to retiring Williams at the earliest feasible date. These conclusions reflect costs only, and do not incorporate considerations related to the benefit of reducing carbon emissions and the risk to customers of higher than anticipated carbon costs in future years. It is worth noting that capital markets increasingly consider failing to plan for the early retirement of coal generation to be a credit negative that can increase costs of capital for a utility.

DESC used data concerning optimized retirement dates to create a range of options to explore the relative costs and CO_2 savings from alternative retirement schedules. Those additional Retirement Options include:

a) Retiring all Units at the earliest achievable retirement dates;

b) Retiring Wateree as early as possible, but allowing William to operate until 2048;

c) As a cost baseline only, allowing all Units to operate until the end of their useful lives for engineering purposes; and

d) Retiring Wateree as early as practicable, but optimizing the retirement date for Williams to provide a basis for assessing the additional cost of retiring Williams earlier than that date.

These alternative cases enable DESC, the Commission and Stakeholders to evaluate trade-offs between costs and carbon emissions between different retirement timelines.

8.2. The Five Market Scenarios

DESC utilized five Market Scenarios each of which reflects a different set of assumptions concerning fuel prices, CO_2 costs, and load growth. DESC based each Market Scenario on internally consistent assumptions about future market and policy drivers dictating the path taken by fuel supplies, environmental regulations and load growth and so embody alternative narrative themes predicting how and why markets might evolve.

DESC developed the five Market Scenarios in consultation with the IRP Stakeholder Advisory group beginning with the August 2021 IRP Stakeholder Advisory group meeting.[11] At this meeting DESC described the key elements that would be included in the retirement study analysis (e.g., load, fuel prices, emissions pressure, etc.) and sought Stakeholder feedback on the proposed approach. Then, in October 2021, DESC shared preliminary market inputs describing reference, high, and low price outlooks of CO_2 and natural gas, then discussed with Stakeholders how these elements could be combined with varying views of load to develop scenarios that would test economic impacts of coal retirements on DESC customers under a range of foreseeable conditions.[12] Following Stakeholder feedback on these preliminary discussions, DESC modified the final set of market scenarios to produce the five narrative themes that represent integrated views of potential future market conditions through the year 2050. These five Market Scenarios are:

[11] https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/MeetingMaterials/DESC_IRP_Stakeholder_Advisory_Group_Session_IV_Slides_2021.08.09.pdf

[12] https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/MeetingMaterials/DESC_IRP_Stakeholder_Advisory_Group_Session_V_Slides_2021.10.25.pdf

Table 3: The Five Market Scenarios

Name	Gas Price	Carbon Price	Load	Scenario Narrative
Reference Case	Base	Base	Base	This scenario reflects a middle-of-the-road outlook and the expected values for key market drivers. While there is currently no explicit price of CO_2 and the design of future policy is uncertain, DESC includes moderate CO_2 pricing in the electric sector as a proxy for future policy that increases the cost of fossil-fired resources.
Zero Carbon Cost[13]	Base	Zero	Base	This scenario includes the expected economic forecast but not an explicit CO_2 cost or constraint. This scenario serves primarily as a point of reference for comparing the results of other scenarios.
Limited Gas Supply	High	Low	Base	Under this scenario, decarbonization goals are pursued through limits on oil and gas production, which combine with continued international demand to produce higher natural gas commodity prices. As a result, less explicit CO_2 pressure is needed to achieve the desired level of electric sector greenhouse gas ("GHG") reductions.
High Electric CO_2 Price	Base	High	Base	Under this scenario, policymakers enact a higher price on electric sector CO_2 emissions earlier than under the Reference Case. The price of natural gas remains at or near expected levels, as production gets more costly and lower electric demand is offset by growth in exports and non-electric demand.
Aggressive Environmental Regulation	High	High	Base + High EVs	Under this view, policymakers enact higher CO_2 prices and also limit oil and gas production resulting in more costly natural gas. The higher cost of alternatives leads to an increase in end-use electrification and higher electric loads than in the other scenarios.

DESC also consulted Stakeholders concerning the appropriate modeling assumptions for cost and performance characteristics of the solar, battery and natural gas fired generation options available to the PLEXOS model. The resulting analysis also accounts for savings that can be achieved through the elimination of ongoing fuel, operations and maintenance expense, capital maintenance expense, environmental compliance costs and other costs that might be saved

[13] This case was denominated the Business as Usual Scenario in material provided to Stakeholders. The name only has changed. There has been no change in assumptions.

through early retirements of Williams and Wateree. It also incorporates the ELG compliance savings that would be achieved by retiring Wateree in 2028. Additional information concerning the specific inputs to the model, and how they were determined, is presented in Section 9 of this Study.

8.3. The Five Retirement Options Evaluated in the Modeling Analysis

DESC evaluated the optimal timing, costs and carbon impacts from retiring the Units by modeling five Retirement Options. The modeling was done in five steps:

- In modeling Retirement Option 1, DESC allowed the PLEXOS model to optimize the Wateree and Williams retirements dates from a cost standpoint under each of the five Market Scenarios and then determine the associated generation portfolios, costs and carbon impacts from retiring the Units at those dates. The results showed an optimum retirement date for Wateree by 2028 in all but one Market Scenario and a range of optimum retirement dates for Williams between 2031 and 2047.
- In modeling Retirement Option 2, DESC allowed the PLEXOS model to optimize generation portfolios under each Market Scenario assuming the earliest reasonably practical retirement dates for the Units consistent with maintaining reliable service to customers considering the information available at present. Therefore, Retirement Option 2 assumes the retirement of Wateree by the end of 2028 and Williams by the end of 2030. The resulting Retirement Option 2 measures the cost impacts and CO_2 savings from a highly aggressive retirement plan.[14]
- In modeling Retirement Option 3, DESC allowed the PLEXOS model to optimize generation portfolios under each Market Scenario assuming Wateree retires in late 2028, and Williams remains in service until in 2047, which is its end of useful life. Comparing Retirement Option 3 (late retirement of Williams) with Retirement Option 2 (early retirement of Williams) provides a measure of the differential in cost from delaying the Williams retirement beyond the earliest reasonably feasible date.
- In modeling Retirement Option 4, DESC allowed the PLEXOS model to optimize generation portfolios under each Market Scenario assuming Wateree and Williams both operate until the end of their useful lives (Wateree 2044 and Williams 2047). The resulting Retirement Option provides a base-line of costs and CO_2 emission levels against which other scenarios can be assessed. It is not intended to indicate that DESC is considering keeping both Wateree and Williams in service until those dates.
- In modeling Retirement Option 5, DESC fixed the early retirement date for Wateree in 2028 and then allowed the PLEXOS model to optimize the Williams retirements date to achieve the lowest cost. The resulting optimization is informed by the finding that retiring Wateree in late 2028 is low cost but also allows the model to validate the retirement dates found in Retirement Option 1 at a lesser level of problem complexity.

8.4. Conclusions of the Economic Modeling

Modeling the five Retirement Options showed:

1. Operating both Wateree and Williams until the end of their useful lives is only the least cost option in the Market Scenario that assumes high natural gas prices and reference CO_2 costs. This scenario measures costs under future conditions that favor the

[14] How practical this plan will be in implementation will depend on information that has not yet been determined, including what fuel supply and delivery resources will be required and whether provided in time to support the planning dates.

continued reliance on coal. In no other scenario is delayed retirement of both Wateree and Williams the least cost option.

2. The end of 2028 is the optimized date for retiring Wateree in four of five Market Scenarios. But these benefits could be eroded if replacement generation cannot be procured to allow Wateree to be retired in time to avoid substantial elements of future ELG compliance costs.
3. The rate impacts from retiring both Wateree and Williams early, compared to retiring Williams at the optimized dates, are low. These dates increase the compound annual growth rate ("CAGR") in the typical residential customer's bill by 0.34% or less over the 15-year rate analysis. However, in three out of the five Market Scenarios, retiring both Wateree and Williams as early as possible leads to the highest costs for customers. Conversely, each of the five lowest cost options involve operating Williams until 2047.

Table 4 shows actual levelized net present values ("LNPV") of costs under each Retirement Option. Figures in green are the lowest cost results under each Market Scenario and those in red are the highest cost. The retirement dates reflected in **Table 4** are based on the conventions used by DESC's Resource Planning Division which accounts for a December retirement date in the following year. Therefore, the year of 2029 in **Table 4** indicates a retirement date by December 31, 2028.

Table 4: 30 Year LNPV of Each Retirement Option ($000)[15]

	RO1 - Optimized[16]		Informed Retirements (Yr)			RO5 - Optimize Williams	
Market Scenario	Retirement (Yr)	Cost	RO2 – Wateree(29) Williams (31)	RO3 – Wateree(29) Williams (48)	RO4 – Wateree(45) Williams (48)	RO5 – Wateree(29) Williams (opt)	Retirement (Yr)
Zero Carbon Cost	Wateree (29) Williams (45)	$1,567,745	$1,583,414	$1,560,759	$1,583,103	$1,565,026	Wateree (29) Williams (47)
Reference Case	Wateree (29) Williams (32)	$1,745,943	$1,744,790	$1,732,618	$1,770,758	$1,747,956	Wateree (29) Williams (33)
Limited Gas Supply	Wateree (32) Williams (48)	$1,906,567	$1,956,203	$1,900,896	$1,896,731	$1,897,946	Wateree (29) Williams (48)
High Electric Sector CO_2 Prices	Wateree (29) Williams (32)	$1,859,636	$1,858,099	$1,848,909	$1,889,270	$1,862,606	Wateree (29) Williams (32)
Aggressive Environmental Regulations	Wateree (29) Williams (44)	$2,165,691	$2,198,436	$2,157,497	$2,180,075	$2,160,040	Wateree (29) Williams (44)

Retiring Wateree by the end of 2028 while operating Williams until the end of its useful life is the lowest cost Retirement Option under four of the five Market Scenarios. This is largely due to the cost of the transmission and natural gas supplies required to maintain reliability in the Southern District of DESC's transmission system after Williams is retired. Delaying these costs drives down the cost of retiring Williams.

Conversely, Retirement Options 3 and 4 show that waiting to retire Wateree until the end of its useful life results in a higher cost for customers in all but one of the five Market Scenarios. Both Retirement Options assume Williams operates until 2047, but Retirement Option 3 retires Wateree early and results in lower costs. Because Wateree operates in a much less constrained part of DESC's transmission grid, and does not provide as critical a reliability

[15] The data presented in these charts is based on the planning convention that places a retirement date in the year following retirement. A 2028 retirement date is shown in 2029 and a 2030 retirement date is shown in 2031. The planning convention is maintained here to preserve continuity between these charts and the spreadsheets that support them.

[16] In several cases, the optimized dates calculated in Retirement Options 1 and 5 are the informed retirement dates in other Retirement Options. Although the retirement dates are the same, the results are slightly different. This is not an error but a function of the way the model cycles through options differently when there is a fixed limitation specified in setting up the scenario, like an informed retirement date, rather than an open item like an optimized date.

function as Williams, the cost of retiring it early are less. It is likely less challenging to replace Wateree than Williams considering the cost of gas supply and transmission upgrades required.

Table 5 below puts the costs associated with retiring Williams early into perspective. In three of the five Market Scenarios, the additional cost on a 30-year LNPV basis of retiring Williams in 2030 compared to operating Williams until its optimized retirement date (Retirement Option 2 vs. Retirement Option 5) is between 1.2% and 3.1%, and is slightly cost-beneficial by 0.2% in two scenarios. Overall, retiring Williams early results in an average annual increase in cost of 1.1%. This translates into an average compound annual rate of growth in LNPV on the order of 0.03%.

Table 5: Difference in 30 Year LNPV of Retiring Williams Early or Optimized ($000)

		Early Williams Retirements vs Optimized			
Market Scenario		RO2 – Wateree(28) Williams (30)	RO5 – Wateree(28) Williams (opt)	Savings ($1,000s)	% Savings
Zero Carbon Cost		$1,583,414	$1,565,026	($18,388)	-1.2%
Reference Case		$1,744,790	$1,747,956	$3,165	0.2%
Limited Gas Supply		$1,956,203	$1,897,946	($58,257)	-3.1%
High Electric Sector C02 Prices		$1,858,099	$1,862,606	$4,508	0.2%
Aggressive Environmental Regulations		$2,198,436	$2,160,040	($38,396)	-1.8%
Average Savings (negative is a cost)				($21,474)	-1.1%

8.5. Conclusions Regarding CO_2 Emissions

Table 6 shows the reduction in CO_2 emissions from DESC's generation system at representative points over the planning horizon. The base year is 2005 which is a standard baseline for emissions reporting under many regulatory schemes. Both Wateree and Williams will have reached the end of their useful lives before 2050 and both will have been retired by then. For that reason, early retirements have only modest impacts on annual carbon emissions in 2050 under all planning assumptions. Accordingly, the comparison that follows focuses on carbon emissions in 2040, which is after the early retirement date of both Wateree and Williams but before the end of their useful lives. In all cases, the reduction in CO_2 emissions are offsetting the effect of rising electrical demand which puts upwards pressure on emissions.

Table 6: Reduction in CO_2 Emissions

	Reduction in CO_2 Emissions			
Market Scenarios	**2022**	**2030**	**2040**	**Cumulative Emissions from 2022 to 2050 (000 tons)**
Retirement Option 1				
Zero Carbon	37%	47%	52%	271,995
Reference Case	37%	53%	61%	236,288
Limited Gas Supply	39%	27%	51%	300,683
High Electric Sector CO_2 Prices	37%	55%	63%	226,904
Aggressive Environmental Regs	39%	46%	56%	268,054
Retirement Option 2				
Zero Carbon	37%	46%	60%	251,738
Reference Case	37%	53%	61%	234,485
Limited Gas Supply	39%	41%	64%	251,951
High Electric Sector CO_2 Prices	37%	55%	63%	226,544
Aggressive Environmental Regs	39%	46%	67%	238,969
Retirement Option 3				
Zero Carbon	37%	47%	51%	278,773
Reference Case	37%	52%	59%	245,695
Limited Gas Supply	39%	39%	51%	293,935
High Electric Sector CO_2 Prices	37%	55%	62%	233,249
Aggressive Environmental Regs	39%	46%	56%	274,899
Retirement Option 4				
Zero Carbon	37%	44%	45%	294,268
Reference Case	37%	50%	56%	255,622
Limited Gas Supply	39%	25%	36%	340,761
High Electric Sector CO_2 Prices	37%	52%	59%	240,177
Aggressive Environmental Regs	39%	40%	49%	292,380
Retirement Option 5				
Zero Carbon	37%	47%	51%	275,520
Reference Case	37%	53%	61%	236,394
Limited Gas Supply	39%	39%	51%	293,825
High Electric Sector CO_2 Prices	37%	55%	63%	226,861
Aggressive Environmental Regs	39%	45%	55%	270,410

Retiring Wateree by the end of 2028 but allowing Williams to operate to the end of its useful life in 2047 (Retirement Option 3) results in an average 7% reduction in DESC's 2040 carbon emissions across all Market Scenarios. This is compared to operating both Wateree and Williams until the end of their useful lives (Retirement Option 4). Under this analysis, retiring Wateree early increases DESC's reduction in carbon levels on average from 49% to 56% from 2005 to 2040 with reductions as high as 62% when Wateree's early retirement is coupled with high CO_2 costs (under the High Electric CO_2 Price Market Scenario). The reduction in CO_2 levels is greater than 50% in all five Market Scenarios. **Table 7** provides the reduction in CO_2 emissions between Retirement Option 3 and 4 for all Market Scenarios:

Table 7: Comparison of 2040 CO_2 Emissions between an Early and Late Retirement of Wateree (Retirement Option 3 v. 4)

	RO3- WAT(28) WMS(47)		RO4 - WAT(44) WMS(47)		RO3 vs RO4
MARKET SCENARIO	Annual kTons	% Reduction from 2005	Annual kTons	% Reduction from 2005	Incremental Reduction from 2005
Zero Carbon	9,204	51%	10,368	45%	6%
Reference Case	7,773	59%	8,358	56%	3%
Limited Gas Supply	9,146	51%	12,004	36%	15%
High Electric Sector CO_2 Prices	7,234	62%	7,657	59%	2%
Aggressive Environmental Regulations	8,221	56%	9,502	49%	7%
RO AVERAGE	**8,316**	**56%**	**9,578**	**49%**	**7%**

Retiring Wateree by the end of 2028 and Williams by the end of 2030 (Retirement Option 2) reduces CO_2 emissions in 2040 on average by 14% compared to operating all Units until the end of their useful lives (Retirement Option 4). This is an incremental improvement of 7% over the Wateree-only early retirement scenario discussed above (i.e., Retirement Options 3 vs. 4). Retiring both Wateree and Williams at their earliest feasible dates increases DESC's 2005 to 2040 reduction in carbon levels on average from 49% to 63% with reductions as high as 67% where both CO_2 emissions costs and natural gas prices are high (the Aggressive Environmental Regulation Market Scenario). Under this analysis, the reduction in CO_2 levels after retiring both Wateree and Williams is greater than 60% in all five Market Scenarios. **Table 8** provides the reduction in CO_2 emissions between Retirement Option 2 and 4 for all Market Scenarios.

Table 8: Comparison of 2040 CO_2 Emissions between Early Retirement of All Units and Operating All Units to End of Useful Life (Retirement Options 2 vs. 4)

	RO2 - WAT(28) WMS(30)		RO4 - WAT(44) WMS(47)		RO2 vs RO4
MARKET SCENARIO	Annual kTons	% Reduction from 2005	Annual kTons	% Reduction from 2005	Incremental Reduction from 2005
Zero Carbon	7,586	60%	10,368	45%	15%
Reference Case	7,270	61%	8,358	56%	6%
Limited Gas Supply	6,681	64%	12,004	36%	28%
High Electric Sector CO_2 Prices	6,930	63%	7,657	59%	4%
Aggressive Environmental Regulations	6,266	67%	9,502	49%	17%
RO Average	**6,946**	**63%**	**9,578**	**49%**	**14%**

The cumulative impacts on carbon emissions from early retirements follow a similar pattern. Compared to operating both Wateree and Williams until the end of their useful lives (Retirement Option 4), retiring all Units at the earliest feasible dates (Retirement Option 2), results in a reduction of between 6% and 26% in cumulative carbon emissions by 2050 with an average reduction of 14.5%. The highest reduction occurs in the Limited Gas Supply Scenario. **Table 9** shows the reduction in cumulative carbon emissions from retiring all of the Units early compared to retiring them at the end of their useful lives.

Table 9: Reduction in Cumulative CO_2 Emissions 2022-2050 from Early Retirement of All Units Compared to Retiring All at the End of Their Useful Lives (Retirement Options 2 vs. 4)

Market Scenario	Percent Reduction
Zero Carbon	-14%
Reference Case	-8%
Limited Gas Supply	-26%
High Electric Sector CO_2 Prices	-6%
Aggressive Environmental Regulations	-18%

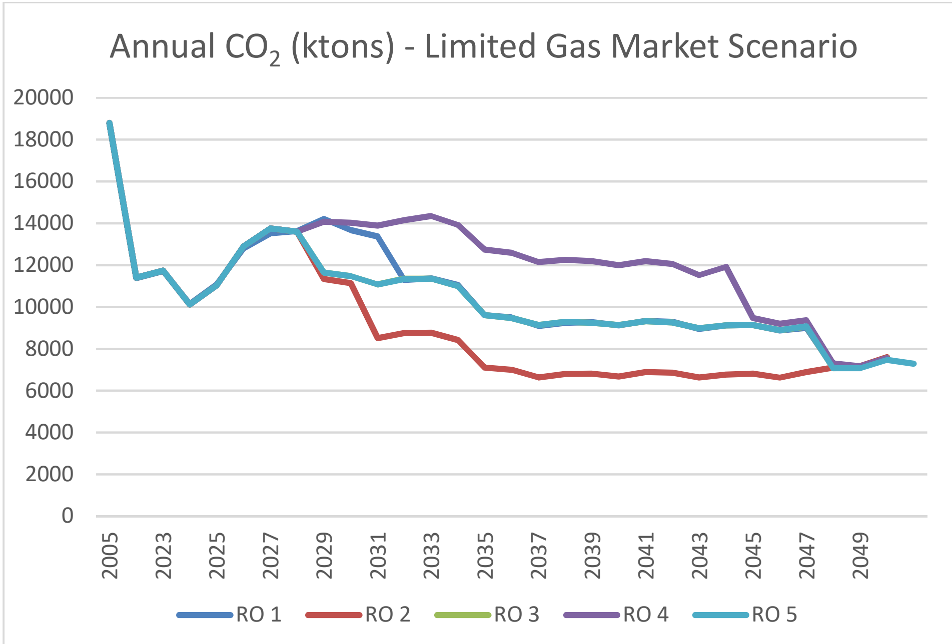
Retiring both Williams and Wateree at the earliest feasible dates (Retirement Option 2) compared to retiring Wateree by 2028 and optimizing the retirement of Williams (Retirement Option 5) reduces cumulative carbon emission 2022-2050 by between 0% and 14% across the five Market Scenarios. The very low incremental reductions under the Market Scenarios for the Reference Case and the High Electric Sector CO_2 Prices reflect the fact that under those Market Scenarios, the timing of optimized retirements are close to the earliest feasible retirement date.

Table 10: Reduction in Cumulative CO_2 Emissions from Early Retirement of all Units Compared to Early Retirement of Wateree and Optimizing Williams retirement (Retirement Options 2 vs. 5)

Market Scenario	Percent Reduction
Zero Carbon	-9%
Reference Case	-1%
Limited Gas Supply	-14%
High Electric Sector CO_2 Prices	0%
Aggressive Environmental Regulations	-12%

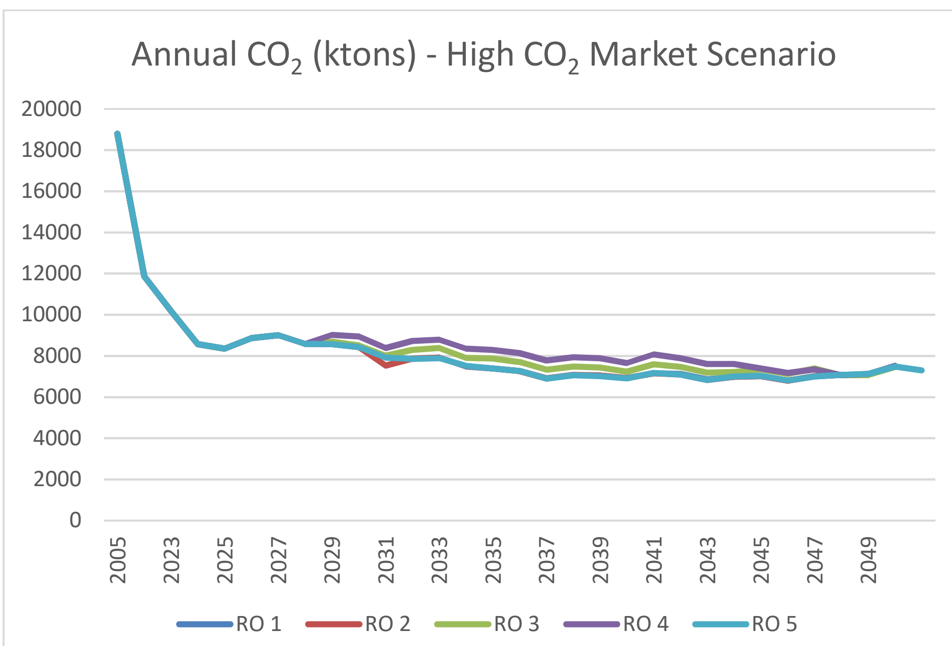
As the results discussed above indicate, the reductions in carbon emission due to early retirements are quite sensitive to the Market Scenario modeled. Under all five Retirement Options, the greatest cumulative reduction in carbon emissions is achieved under the Limited Gas Supply Market Scenario which shows strong variability in emissions as Unit retirements are achieved. **Figure 4** shows this reduction graphically by year:

Figure 4: Carbon Reductions by Retirement Options under Market Scenario 3 (Limited Gas Supply).



By contrast, **Figure 5** shows that when high CO_2 costs and base gas prices are assumed (the High Electric Sector CO_2 Prices Market Scenario) the incentive to rely on coal units for energy is reduced and the impact of early retirements on CO_2 emissions is also reduced.

Figure 5: Carbon Reductions by Retirement Options under Market Scenario 4 (High Electric Sector CO_2 Prices).



Similar charts for the three other Market Scenarios are attached as **Appendix D.**

8.6. Rate Impact Analysis

To assess the impact on retail rates over a 15-year review period, DESC converted the incremental changes in generation and transmission costs under each of the Retirement Options into anticipated rate changes. This rate analysis considered only the costs modeled in the comparative economic evaluation. It does not take into account changes in the other categories of costs that are reflected in rates. As such, it provides a comparative assessment of the rate impact of the Retirement Options but not a comprehensive forecast of future rates which involves many additional factors.[17]

The comparative evaluation of the Retirement Options takes place against a baseline of increases caused by changes in fuel prices, CO_2 emissions costs, and other generation investments not associated with coal unit retirements (*i.e.,* investments to meet load growth and to maintain units that remain in service). These changes apply across all five Retirement Options and Market Scenarios in varying degrees. For example, under Retirement Option 4, which assumes no early retirements, the CAGR for those cost that are modeled in this Study is between 1.83% and 3.03% depending on the Market Scenario chosen. **Table 11** shows the CAGR in the typical customer's monthly bill under each Retirement Option and Market Scenario.[18]

Table 11: Compound Annual Growth Rate in Typical Monthly Bills for Residential Customers 2022- 2036 under Each Retirement Option and Market Scenario Evaluated

Typical Monthly Residential Bill @1000KWh	Retirement Option 1 (Optimized)	Retirement Option 2 (Wat28/Wms30)	Retirement Option 3 (Wat28/Wms47)	Retirement Option 4 (Wat44/Wms47)	Retirement Option 5 (Wat28/Wms Optimized)
Zero Carbon	1.73%	1.90%	1.70%	1.83%	1.75%
Reference Case	2.27%	2.24%	2.09%	2.25%	2.22%
Limited Gas Supply	2.51%	2.83%	2.48%	2.45%	2.49%
High Electric Sector CO_2 Prices	2.49%	2.45%	2.35%	2.50%	2.53%
Aggressive Environmental Regulations	2.97%	3.25%	2.95%	3.03%	2.94%

17 The costs modeled in the Study represent approximately 80% of a typical retail customer's total bill in 2022. Because the costs modeled in the Study increase, while the costs not modeled in the Study remain unadjusted, by the end of the modeling period, the costs modeled in the Study grow to as much as 83% of a typical customer's bill. By convention, a typical customer is assumed to be a residential Rate 8 customer using 1,000 kWh per month.

18 For comparative purposes, a typical customer is a residential Rate 8 customer using 1,000 kWh per month.

As shown in **Table 12**, retiring Williams and Wateree at the earliest feasible dates (Retirement Option 2), compared with operating them until the end of their useful lives (Retirement Option 4) results in upward pressure on rates of between 0.07% and 0.38% in three of the five Market Scenarios. Under the High CO_2 Price and Reference Case, early retirement results in slight downward pressure on rates of 0.05% and 0.01%. The highest increase in rates occurs under the Limited Gas Supply scenario. These effects would be spread over 15 years such that the change in the year to year increase in these costs, i.e., the CAGR, would in all cases be 0.38% or less.

Table 12: Rate Differential from the Early Retirement of All Units Compared to Retiring All at the End of Their Useful Lives (Retirement Options 2 vs. 4)

Market Scenario	Rate Difference between Retirement Options 2 and 4 in 2036
Zero Carbon	0.07%
Reference Case	-0.01%
Limited Gas Supply	0.38%
High Electric Sector CO_2 Prices	-0.05%
Aggressive Environmental Regulations	0.23%

Retiring both Williams and Wateree at the earliest feasible dates (Retirement Option 2) compared to retiring Wateree early, in 2028, and optimizing retirement for Williams (Retirement Option 5) results in increased rates across four of the five Market Scenarios ranging from 0.07% and 0.34%. The only decrease in the CAGR occurs under the High CO_2 Cost Market Scenario.[19] The Limited Gas Supply Market Scenario resulted in the highest cost differential. **Table 13** provides the forecasted differential in a typical monthly bill for residential customers under Retirement Options 2 and 5.

[19] The fact that the optimized retirement date results in a higher cost than an informed retirement date in this case is an artifact of how the model cycles through options differently when there is a fixed limitation specified in setting up the scenario, like an informed retirement date, rather than an open item like an optimized date. *See* Note 18, above. Under the High CO_2 scenario, the early retirement date for Williams and the optimized retirement dates are only two years apart. The lower cost for early retirement is less than one-tenth of one percent.

Table 13: Rate Differential from the Early Retirement of All Units Compared to Optimizing retirement of Williams (Retirement Options 2 vs. 5)

Market Scenario	Rate Difference between Retirement Options 2 and 5 in 2036
Zero Carbon	0.15%
Reference Case	0.02%
Limited Gas Supply	0.34%
High Electric Sector CO_2 Prices	-0.08%
Aggressive Environmental Regulations	0.31%

8.7. Reliability Assessment

Ensuring reliability is a key consideration in planning the retirement of major generating facilities. Reliability considerations factor in all aspects of this Study. It is the primary focus of the TIA, which uses power flow models based on FERC and NERC approved reliability standards to estimate the transmission upgrade costs entailed in location-specific options for replacing retiring capacity resources and location-specific upgrade projects to support those resources. This modeling assesses the ability of both the transmission and generation system to meet customer demands at peak periods assuming the loss of lines and generation resources as specified in the approved reliability criteria.

This Study's portfolio optimization modeling uses the PLEXOS software model to identify the optimum resource portfolios to meet customers' demands when the Units are retired while meeting certain reliability criteria. Through these criteria, the PLEXOS model includes parameters that capture important reliability attributes such as reserve margin, contingency reserve requirement, ramp-rates, must-run units, and Automatic Generation Control ("AGC") requirements. DESC also discussed reliability evaluation with Stakeholders as part the IRP Advisory Group process and adopted some Stakeholder suggestions.[20]

This modeling, like that in the IRP, identifies resources by type but not location. It assumes that all transmission-related locational costs are captured in the TIA or will be captured in Large Generator Interconnection studies that are performed once preferred generation plans are selected and both of which are location specific. Generic representations of those interconnection costs are included in the optimization model to represent the costs associated with transmission upgrades needed to support new generating units but location specific costs are not.

[20] https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/MeetingMaterials/DESC_IRP_Stakeholder_Advisory_Group_Session_IV_Slides_2021.08.09.pdf and https://www.desc-irp-stakeholder-group.com/Portals/0/Documents/MeetingMaterials/DESC_IRP_Stakeholder_Advisory_Group_Session_V_Slides_2021.10.25.pdf

Reserve Margin: PLEXOS is instructed to maintain the 21% winter Reserve Margin Requirement as resource additions and retirements are considered and selected in every year of the study horizon. Each PLEXOS build plan results in a Loss-of-Load-Expectation of less than one loss-of-load event every ten years which is the maximum allowed for resource adequacy. A Reserve Margin requirement is a minimum and cannot and should not be used as a target or maximum limit. Doing so is impractical since cost-effective resource additions come in increments that routinely take the Reserve Margin above 21% as they are added to the generation portfolio.

Ramp Rates: Ramp rates are the times required by a unit to increase or decrease electric generation as the balance between load and resource shift throughout the day. As an example, PLEXOS must find a blend of resources that can operate at low loads at night and ramp up, increasing output in the early morning as customer loads build to a peak at about 7:30 A.M. at sunrise. Following the peak period and as the customer load drops, online generation must ramp down. These ramps are different each day and can be challenging in both absolute rate and duration. Also just after sunrise, photovoltaic solar generation, a non-dispatchable resource, rapidly increases power output regardless of customer need and interchange balance which contributes to and often is solely responsible for the downward ramp of dispatchable generation. PLEXOS is programmed to recognize this need for ramping resources and optimizes considering ramping requirements.

AGC: AGC is needed to follow load instantaneously or nearly so. Although PLEXOS is solving for hourly increments, it must provide amounts of regulating reserves to provide AGC over smaller increments of time required to meet reliability standards. This requirement is included in the model and PLEXOS selects resources to provide this reliability requirement as the optimized build plans are constructed. Many of the candidate resources available within PLEXOS have AGC capability.

In addition, as it determines an optimal generation portfolio, PLEXOS also values a resources' ability to contribute long-duration energy storage, limited-duration energy storage, output coincident to system peak load, dispatchability, and operational flexibility.

DESC consulted with Stakeholders to develop the reliability factors to evaluate the generation portfolios optimized for each Retirement Option under each Market Scenario. Reliability factors include those that are accounted for explicitly in the PLEXOS modeling, those that must be accounted for through TIA or Large Generator Interconnection studies, and those that must be independently evaluated as part of the Study.

These reliability factors that are accounting for in the PLEXOS modeling are listed below:

- Coincident Peak[21]
- Energy Storage
- Limited Energy Storage
- Dispatchability
- Operational Flexibility
- Secondary Frequency Response

[21] Because winter peaks often occur where there is little or no sunlight, incremental PV Solar has no value coincident to the winter peak.

The specific values of these attributes vary by resource type and are valued as part of the PLEXOS optimization.

Included in **Tables 14** through **19** below is the Reliability Factors' evaluation conducted on the optimized build plans from the Retirement Option 1 results. This list of Reliability Factors has been reduced from a previous analysis in the Modified 2020 IRP as a result of input from DESC's Transmission Planning Department and Stakeholders and analysis provided in the PLEXOS model. In those discussions, the Reliability Factors that were better served exclusively by DESC's Transmission Planning Department or within the PLEXOS optimization were identified and removed. Black start, offline fast start, geographic diversity and proximity to load are attributes that can be evaluated by valuing the changing contribution of resources over the planning horizon. In this simple evaluation, each resource type is credited with attributes commensurate with its specification within the PLEXOS model.

The reliability factors that must be evaluated outside of PLEXOS are set out in **Table 14**.

Table 14: Reliability Factors Evaluated Outside PLEXOS

Potential Reliability Attribute[22]	Coal Units	Aero CT	Frame CT	Gas CC	Solar PV	Paired Battery Storage	Stand Alone Battery Storage
Black Start	No	Yes	Yes	No	No	No	No
Fast Start	No	Yes	Yes	No	No	Yes	Yes
Geographic Diversity	No	No	No	No	No	No	Yes
Proximity to Load	Yes[23]	Yes	Yes	Yes	No	No	Yes

Using these factors, DESC evaluated the contributions to reliability for each of the Market Scenarios identified in the PLEXOS modeling. The results are as follows:

[22] PPA terms, as-built specifications, or operational use case could impact each

[23] Williams Station's location is near a major load center and provides essential reliability attributes in the Charleston Metroplex, Wateree Station is not credited.

Table 15: Reliability Factors for the Zero Carbon Cost Market Scenario Optimized Build Plan - RO1

Reliability Factors Impact	Coal Unit	Aero CT	Frame CT	Gas CC	Solar PV	Battery Storage	Stand Alone Battery Storage	Total Change (MW equiva-lent)
Black Start	-	261	1,046	-	-	-	-	1,307
Fast Start	-	261	1,046	-	-	750	488	2,544
Geographic Diversity	-	-	-	-	-	750	488	1,238
Proximity to Load	(610)	261	1,046	-	-	-	488	1,184

Table 16: Reliability Factors for the Reference Market Scenario Optimized Build Plan - RO1

Reliability Factors Impact	Coal Unit	Aero CT	Frame CT	Gas CC	Solar PV	Battery Storage	Stand Alone Battery Storage	Total Change (MW equiv-alent)
Black Start	-	495	523	-	-	-	-	1,018
Fast Start	-	495	523	-	-	750	525	2,293
Geographic Diversity	-	-	-	-	-	750	525	1,275
Proximity to Load	(610)	495	523	-	-	-	525	933

Table 17: Reliability Factors for the Limited Gas Market Scenario Optimized Build Plan - RO1

Reliability Factors Impact	Coal Unit	Aero CT	Frame CT	Gas CC	Solar PV	Battery Storage	Stand Alone Battery Storage	Total Change (MW equiva-lent)
Black Start	-	375	523	-	-	-	-	898
Fast Start	-	375	523	-	-	750	563	2,210
Geographic Diversity	-	-	-	-	-	750	563	1,313
Proximity to Load	(610)	375	523	-	-	-	563	850

Table 18: Reliability Factors for the High Carbon Cost Market Scenario Optimized Build Plan - RO1

Reliability Factors Impact	Coal Unit	Aero CT	Frame CT	Gas CC	Solar PV	Battery Storage	Stand Alone Battery Storage	Total Change (MW equiva-lent)
Black Start	-	375	523	-	-	-	-	898
Fast Start	-	375	523	-	-	750	713	2,360
Geographic Diversity	-	-	-	-	-	750	713	1,463
Proximity to Load	(610)	375	523	-	-	-	713	1,000

Table 19: Reliability Factors for the High Regulation Market Scenario Optimized Build Plan - RO1

Reliability Factors Impact	Coal Unit	Aero CT	Frame CT	Gas CC	Solar PV	Battery Storage	Stand Alone Battery Storage	Total Change (MW equiva-lent)
Black Start	-	609	-	-	-	-	-	609
Fast Start	-	609	-	-	-	750	563	1,921
Geographic Diversity	-	-	-	-	-	750	563	1,313
Proximity to Load	(610)	609	-	553	-	-	563	1,114

In summary, with the TIA as the central facet, the Retirement Study has assessed the reliability impact of coal plant retirements. Incorporating the key results of the TIA in the PLEXOS modeling incorporates reliability to the maximum extent possible without identifying actual replacement projects. Ultimately, the Interconnection Study process will evaluate the reliability impacts of individual new generation projects and those paired with unit retirements. Through the IRP and RFP, actual locationally specific projects will emerge and will only be selected if system reliability contributions are adequate. Using this Retirement Study as an indicator, reliability is contingent on the ability to build natural gas-fired or thermal resources as coal units are retired and customer load continues to grow. Lower carbon emissions and reliability are not mutually exclusive, yet thermal generation units must be added with renewable resources to ensure reliability while adding more renewable generation will displace more and more energy from thermal units. This could drastically lower carbon emissions while the thermal units back-stand intermittent renewable resources and maintain the required levels of reliability.

9. Inputs and Assumptions in the Economic Evaluation Modeling

In conducting the economic modeling of the five Retirement Options, DESC reviewed and refined inputs concerning cost savings from retiring the Units (O&M, capital maintenance, environmental and other capital upgrades), future fuel cost forecasts, load growth projections, carbon costs, and replacement technology costs (including heat rates, capacity factors, and O&M costs). DESC has done so in close consultation with the Stakeholders and in consideration of Commission mandates concerning modeling inputs to be used in the IRP process.

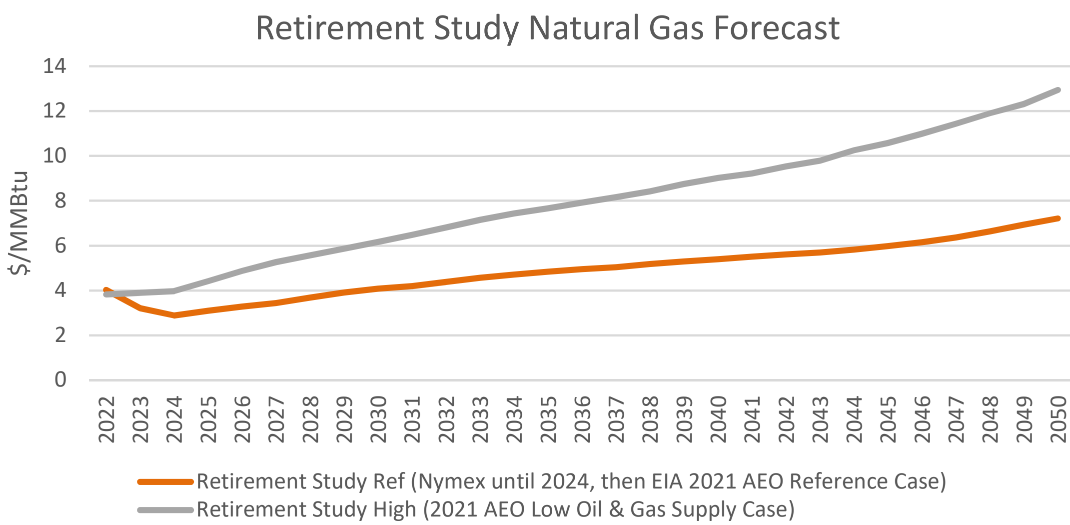
9.1. Natural Gas Prices

DESC developed two natural gas price views for the Retirement Study, as illustrated below in **Figure 6**.[24] The "Base" gas price view relies on NYMEX forwards pricing through 2024, after which the price reflects the Energy Information Administration ("EIA") 2021 Annual Energy Outlook ("AEO") Reference Case as reported in the April 2021 Annual Energy Outlook.[25] Under this view, prices fall over the first two years of the forecast, in line with recent NYMEX futures then rise modestly reaching approximate $7/MMBtu in nominal terms by 2032. The "High" gas price review was taken from the AEO 2021 Low Oil and Gas Supply case. Under this view, prices rise throughout the forecast period approaching $11/MMBtu in nominal terms by 2050. This high price view was selected in response to Stakeholder comments that DESC should consider a wider range of natural gas prices that capture the potential for short-term price increases.

[24] DESC originally proposed three natural gas price forecasts to the IRP Advisory Stakeholder group, however, in response to Stakeholder feedback, the "Low" natural gas view was removed prior to final Retirement Study modeling.

[25] https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf

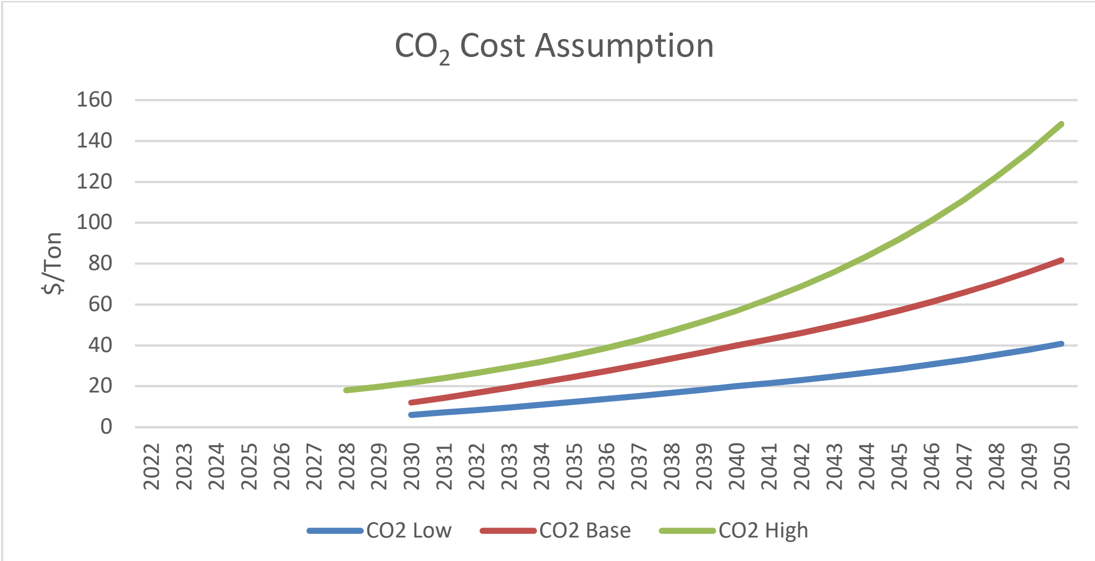
Figure 6: Retirement Study Natural Gas Prices (Henry Hub)



9.2. Carbon Prices

DESC developed four CO_2 pricing views for this Retirement Study to reflect the wide range of possible emissions pricing pressure that may or may not develop over the coming decades. The “Zero” price trajectory was used in the Zero Carbon Cost scenario, reflecting a continuation of current state and federal policies that do not put any explicit price on CO_2 emissions. Under the “Base” CO_2 price view, DESC relied on the IHS “US Power Sector” forecast. Under this view a CO_2 price is enacted starting 2030 at about $12/ton, it then rises steadily over the forecast period to more than $80/ton in nominal terms by 2050. Under the “Low” view of CO_2 prices, DESC assumed that prices would initiate in 2030, but at half the level forecast by IHS. Finally, for the “High” view of CO_2 prices, DESC assumed that CO_2 prices would start two years earlier in 2028, and be 50% higher at $18/ton. **Figure 7** below illustrates the four CO_2 price trajectories used in this Retirement Study.

Figure 7: Retirement Study CO_2 Price Forecasts



9.3. Load Forecast

The peak demand forecasted growth is determined by the customer and sales forecast using the load characteristics of the different customer classes developed as part of DESC's Load Research Program. Historical load data is correlated with historical economic data measuring the level of economic activity in the service territory and adjusted for the effect of energy efficiency gains due to increased Federal and state efficiency standards for items like appliances, lighting, HVAC units and building envelopes and specific load reduction due to DESC's current and anticipated demand side management ("DSM") and energy efficiency ("EE") programs. Forecasts of future levels of economic activity is then used to forecast loads into the future.

In Order No. 2020-832, the Commission ordered DESC to modify its approach to load forecasting for the 2023 IRP docket, Docket No. 2019-226-E, and to "work with [S]takeholders to develop a wide but plausible range of load forecasts[.]" That work is scheduled to be completed in time for the 2023 IRP and the retirement modeling presented at that time is expected to be based on revised methodology. The current load forecast has been updated to 2021 and is based on the methodology described in the 2020 IRP. Several comparisons of forecasted to historical growth in customers and sales were used to develop and benchmark the reasonableness of the forecast.[26]

Due to the increase in electric vehicles ("EV") availability and rapid market growth, for purposes of this Study DESC has updated the assumptions concerning EV growth in the load forecast analysis. While to date the overall penetration of EVs has been somewhat low, i.e., less than 0.14% of all vehicles registered in South Carolina in 2022, data from the South Carolina Department of Motor Vehicles ("DMV") shows a rapid growth with EV registrations growing from 6,300 at the end of 2020 to 7,694 in mid-year 2021 to 10,000 at year-end 2021.

[26] For the purpose of this study and to prevent further delay as that stakeholder process is not been finalized yet, the same methodology used in the 2020 Modified IRP is used in this study. For more details on the methodology, see Revised Modified 2020 IRP filed May 24, 2012, Docket No. 2019-226-E.

DESC expects EVs to have the largest initial impact on distribution systems in urban growth areas. Although much of the DESC service territory is rural, the Charleston and Columbia Metropolitan areas, as well as the coastal areas, are seeing EV growth. The overall demographics, DESC's partnership with the Charleston Area Regional Transportation Authority, and plans by private entities to add larger more robust charging stations in the Charleston and Columbia metro areas and along major transportation corridors in South Carolina are helping EV growth. Charleston Area Regional Transportation Authority has already placed 13 Proterra and New Flyer transit buses in service as of March 2022 with 33 on site. By July/August of 2022 all 33 should be up and running. Each bus will require an estimated 80,000 kWh per year and up to a peak demand of 125 kW.

As battery prices are decreasing and driving down the cost of EVs, they will appeal to a broader cross section of South Carolina customers. Like Charleston, adoption rates are expected to increase in markets like Columbia, Hilton Head and Aiken. The local distribution impacts will certainly require additional planning and investments. A single Tesla supercharger charging bay has a maximum rated output of 250 kW, which is almost 40 times that of a residential water heater. Commonly arranged in eight to sixteen charging bays, the supercharger station could demand 1.5 MW of new load in a single location. Urban distribution systems will need automation and hardening in the next few years.

Table 20 shows an estimate of the number of registered vehicles in DESC's territory over the next 15 years.

Table 20: EV Growth Scenarios

	Aggressive			Base		
Year	BEV	PHEV	Total Vehicle Count (BEV, PHEV and Traditional)	BEV	PHEV	Total Vehicle Count (BEV, PHEV and Traditional)
2022	3,637	1,360	1,311,004	2,775	1,400	1,310,885
2023	5,689	1,734	1,346,633	4,117	1,809	1,346,423
2024	8,288	2,193	1,385,245	5,839	2,308	1,384,930
2025	11,589	2,768	1,426,874	8,025	2,920	1,426,431
2026	15,806	3,479	1,471,205	10,797	3,669	1,470,609
2027	21,218	4,375	1,517,767	14,274	4,580	1,516,975
2028	28,166	5,503	1,566,466	18,609	5,686	1,565,421
2029	37,171	6,933	1,617,288	24,007	7,027	1,615,913
2030	48,411	8,616	1,669,816	30,446	8,534	1,668,025
2031	62,267	10,591	1,723,443	37,906	10,198	1,721,120
2032	78,769	12,823	1,777,242	46,446	12,012	1,774,293
2033	97,691	15,249	1,830,166	56,075	13,959	1,826,525
2034	118,122	17,727	1,881,209	66,793	16,013	1,876,887
2035	139,902	20,236	1,929,696	78,556	18,158	1,924,711
2036	162,535	22,860	1,975,229	90,906	20,427	1,969,595

Table 21 shows DESC's annual sales and its gross peak demand, *i.e.,* its total internal demand, by season over the next fifteen years under a Reference EV and High EV forecast. The Reference EV load forecast assumes an EV market share of about 2.9% by 2035, while the High EV forecast assumes a 25% higher availability of battery electric vehicles ("BEV") and plug-in electric vehicles ("PHEV") and a ban on Internal Combustion Engine Vehicles ("ICEV") by 2030. The Reference EV forecast also assumed the cost for batteries for BEVs by 2025 will be $104/kWh, and $84/kWh for the High EV forecast.

Table 21: Annual Energy and Peak Forecast

	Reference EV			High EV		
Year	**Sales GWh**	**Summer MW**	**Winter MW**	**Sales GWh**	**Summer MW**	**Winter MW**
2021	23,628	4,573	4,984	23,628	4,573	4,984
2022	24,143	4,888	5,035	24,143	4,888	5,035
2023	24,225	4,935	4,893	24,225	4,935	4,893
2024	23,569	4,790	4,907	23,577	4,791	4,908
2025	23,652	4,800	4,926	23,665	4,803	4,926
2026	23,767	4,810	4,939	23,783	4,813	4,940
2027	23,870	4,819	4,953	23,895	4,823	4,954
2028	23,965	4,827	4,964	23,998	4,834	4,966
2029	24,046	4,835	5,016	24,092	4,843	5,018
2030	24,298	4,883	5,067	24,358	4,895	5,071
2031	24,538	4,936	5,121	24,619	4,953	5,126
2032	24,817	4,989	5,176	24,921	5,010	5,183
2033	25,088	5,045	5,232	25,225	5,073	5,241
2034	25,370	5,100	5,287	25,538	5,133	5,300
2035	25,682	5,155	5,339	25,881	5,194	5,355

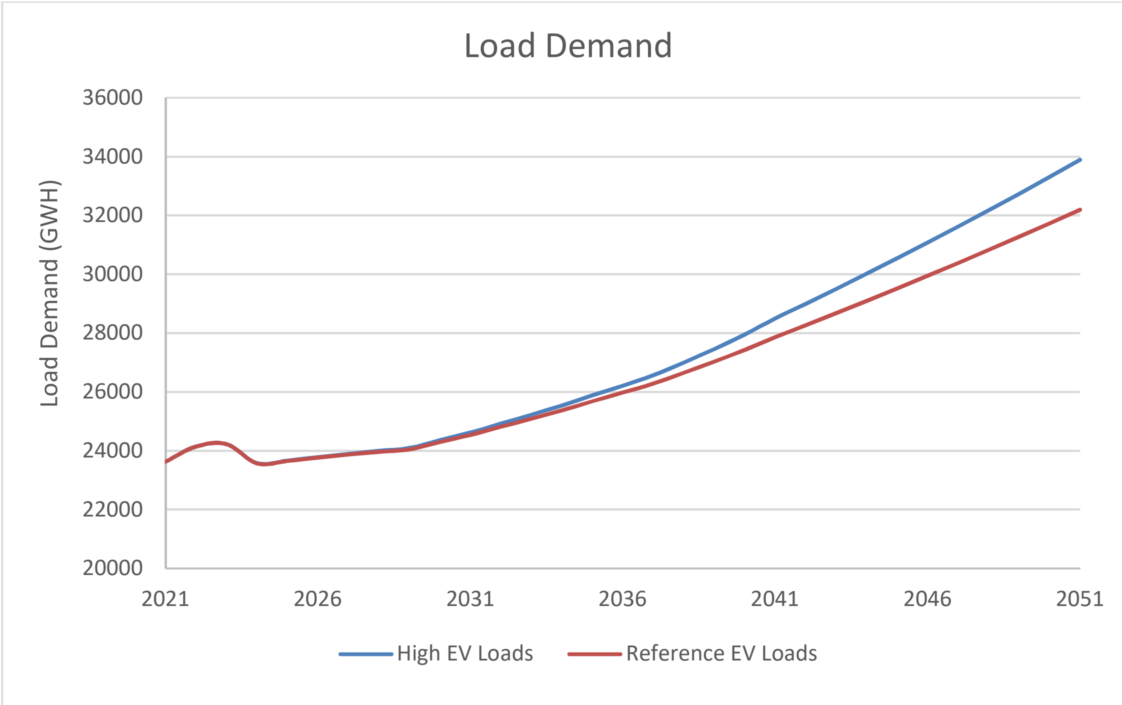
Over this planning horizon, DESC is projecting through its statistical and econometric forecasting models that sales will grow at 0.6% while the summer and winter peak demands both grow at 0.9 and 0.5%. respectively. **Table 22** shows DESC's projected demand response capacity and the resulting net firm peak demand, i.e., net internal demand, by season.

Table 22: Net Firm Peak Demand

	Reference EV				High EV			
	Demand Response		Net Firm Peak		Demand Response		Net Firm Peak	
Year	Summer MW	Winter MW	Summer MW	Winter MW	Summer MW	Winter MW	Summer MW	Winter MW
2021	241	237	4,332	4,747	241	237	4,332	4,747
2022	241	238	4,647	4,797	241	238	4,647	4,797
2023	242	214	4,693	4,679	242	214	4,693	4,679
2024	218	215	4,572	4,692	218	215	4,573	4,693
2025	219	216	4,581	4,710	219	216	4,584	4,710
2026	220	217	4,590	4,722	220	217	4,593	4,723
2027	221	218	4,598	4,735	221	218	4,602	4,736
2028	222	219	4,605	4,745	222	219	4,612	4,747
2029	223	220	4,612	4,796	223	220	4,620	4,798
2030	224	221	4,659	4,846	224	221	4,671	4,850
2031	225	222	4,711	4,899	225	222	4,728	4,904
2032	226	223	4,763	4,953	226	223	4,784	4,960
2033	227	224	4,818	5,008	227	224	4,846	5,017
2034	229	225	4,871	5,062	229	225	4,904	5,075
2035	230	226	4,925	5,113	230	226	4,964	5,129

Figure 8 shows the projected load demand over the next 20 years that was used in the Retirement Study Market Scenarios.

Figure 8: DESC 30-year Load Demand Forecasts.



9.4. Replacement Technology Capital and Operating Costs and Capabilities

To estimate the costs and benefits of early retirements on customer costs, DESC defined a limited set of replacement technologies in consultation with the IRP Stakeholder Advisory Group including both owned options and resources procured via PPAs. The 2023 IRP will present a preferred plan for replacement options once a full analysis of costs and constraints are available. **Table 23** below lists the replacement options that were modeled in this Retirement Study and summarizes their basic characteristics.[27]

[Table begins on following page]

[27] A more detailed and confidential version of this information describing the exact inputs used in the PLEXOS modeling was provided to interested Stakeholders for comment as part of the Stakeholder engagement process.

Table 23: Retirement Study Replacement Technology Options

	Fixed (2022$/Kw-yr)	CAPEX Costs (2022$/kW)	Basis for Cost Assumptions
Solar PV (Utility Owned)	$23.33	$1374.21	Fixed is only Fixed O&M. Both Fixed and Capital Cost values are from NREL 2021 Annual Technology Baseline, Advanced Case.
Battery Storage (Utility Owned)	$30.88	$1251.98	Fixed is only Fixed O&M which "include augmentation costs needed to keep the battery system operating at rated capacity for its lifetime." Both Fixed and Capital Cost values are from NREL 2021 Annual Technology Baseline, Advanced Case.
Solar PV (PPA)	$82.76		Fixed is PPA price which includes all costs and is developed from NREL 2021 Annual Technology Baseline, Advanced Case.
Hybrid Solar + Storage Unit (PPA)	$123.68		Fixed is PPA price which includes all costs and is developed from NREL 2021 Annual Technology Baseline, Advanced Case.
Aeroderivative Combustion Turbine (Utility Owned)	$36.39	$1660.37	Fixed Costs Includes Fixed O&M + Ongoing Capital + Fixed Fuel costs. Costs are from Dominion Energy Green Sheets and DESC's experience with similar units.
Aeroderivative Combustion Turbine - Pair (Utility Owned)	$32.66	$1232.37	Includes Fixed O&M + Ongoing Capital + Fixed Fuel costs. Costs are from Dominion Energy Green Sheets and DESC's experience with similar units.
Frame Combustion Turbine – Pair (Utility Owned)	$97.46	$658.37	Includes Fixed O&M + Ongoing Capital + Fixed Fuel costs. Costs are from Dominion Energy Green Sheets and DESC's experience with similar units.
1x1 Combined Cycle (Utility Owned)	$105.88	$1685.77	Includes Fixed O&M + Ongoing Capital + Fixed Fuel costs. Costs are from Dominion Energy Green Sheets and DESC's experience with similar units.
2x1 Combined Cycle (Utility Owned)	$101.07	$1279.77	Includes Fixed O&M + Ongoing Capital + Fixed Fuel costs. Costs are from Dominion Energy Green Sheets and DESC's experience with similar units.

DESC relied on two key sources to develop assumptions for the replacement resources in this Retirement Study. Based on feedback provided by Stakeholders, DESC relied on the National Renewable Energy Laboratory ("NREL") 2021 Annual Technology Baseline report for new solar and battery storage cost assumptions.[28] DESC assumed that costs for these technologies would evolve over time based on NREL's "advanced" technology innovation view, which

[28] https://atb.nrel.gov/electricity/2021/data

represents the greatest level of improvements covered by the report.[29] Cost of new thermal resources in this Retirement Study were based on estimates developed by Dominion Energy and reflected in the Company's "Green Sheets". The Green Sheets reflect market data collected by the Company through recently completed RFP processes, as well as the Company's own experience building these resources.

9.5. Operations and Maintenance and Capital Costs for the Units

Retiring the Units will save customers the ongoing cost of operating and maintaining them as well as the cost of capital invested to keep them operating safely and reliably. Not including ELG capital costs, Wateree has on-going ELG O&M costs of $3.6M/year. Williams will have on-going ELG O&M costs of $3.87M/year. Normal operations and maintenance costs are expected to remain consistent until the final months of operation and are $11.4M/year for Wateree and $16.8M/year for Williams. DESC has used current and historical budget information concerning these costs with appropriate adjustments for escalation in establishing these costs.

9.6. ELG Costs Compliance

On August 31, 2020, the EPA finalized revisions to the ELG for steam electric power generating Units. The final rule established updated standards for wastewater discharges, setting new limitations on the discharge of FGD wastewater and Bottom Ash Transport Water ("BATW"). Affected facilities are required to convert from wet coal ash management systems to dry or closed cycle systems, and potentially make other changes to wastewater treatment facilities to meet the new discharge limits related to these systems. Williams and Wateree will require action to comply with the new ELG rule if they remain in service after December 31, 2028. The primary driver of compliance costs with the ELG rule is associated with the plant modifications required for compliance with the FGD wastewater provisions of the rule.

DESC is currently evaluating plans for use of Best Available Technology ("BAT") for FGD wastewater treatment at Williams. This compliance pathway requires compliance with the FGD effluent standards by no later than December 31, 2025. The anticipated modifications necessary at Williams include the following major process systems and infrastructure installations:

- Equalization Tanks for the storage and blending of FGD scrubber effluent water;
- Physical/Chemical Treatment for the removal of certain entrained metals, particulate and solids in the FGD scrubber effluent water;
- Biological Treatment for the removal of organic compounds from the FGD scrubber effluent water; and
- Ultrafiltration System for the final treatment of the FGD scrubber effluent water prior to discharge.

These additional infrastructure installations will also be required:

- New buildings to protect process equipment from weather events;
- New foundations to support the process equipment and buildings;
- Electrical power supply extension for the new process equipment;

[29] https://www.nrel.gov/docs/fy21osti/80095.pdf

- Instrumentation and controls for the process equipment; and
- Plant utility extension, compressed water, storm water collection and plant service water.

DESC obtained an Engineers' Opinion of Probable Cost to install the necessary upgrades to comply with the new ELG rules. The Opinion was prepared in accordance with the Association for the Advancement of Cost Estimating ("AACE") definitions and is considered a Class V Estimate. The Opinion's estimate of the process, electrical and control equipment costs for the ELG wastewater treatment project at Williams is estimated to cost $15MM. The equipment costs and installation factors are anticipated to range between $60MM to $75MM.

The Opinion's estimated costs of complying with the ELG rule are included in the capital cost forecasts used in modeling those resources in this Study, and are reflected in **Table 24**.

Table 24: ELG Costs in 2021$

	Wateree	Williams
Compliance Pathway Assumed	Voluntary Incentive Program	Best Available Technology
Compliance Date	No later than December 31, 2028	No later than December 31, 2025
ELG Costs	$110.1M	$90M
ELG O&M	$3.6M/year	$3.87M/year

It should be noted in the table above that the ELG compliance costs for Williams include upgrades for ash transport waters and FGD wastewater. The compliance costs for Wateree are only for FGD wastewater as the plant will be in compliance with the ash transport water requirements of the rule by December 31, 2024 and these costs are already sunk cost that do not affect modeling future costs.

If Williams were to transition from the BAT compliance approach to the Voluntary Incentive Program ("VIP") approach, compliance costs would increase as this approach to FGD wastewater treatment relies upon developing advanced wastewater management technologies that are not yet common in the marketplace. The VIP does provide an automatic compliance date of December 31, 2028, but at higher compliance costs and technical risk.

Wateree opted-in to the VIP structure as that plant is anticipated to run in a more cyclic operating regime than Williams in the future. Such an operating regime is not compatible with the operation of biological wastewater treatment (as is included in the BAT approach) and as such, the plant had to opt into the VIP approach.

9.7. Other Costs and Considerations

Decommissioning and retirement costs for each unit were estimated by utilizing $20/kW as the assumed cost factor for decommissioning and demolition costs based on recent experience with DEV and consistent with Canadys Station demolition costs. Retirement for Williams is expected to be approximately $12.1M, and retirement for Wateree is expected to be approximately $13.68M. These costs will include demolition of existing structures and closure of the sites.

DESC will incur the decommissioning and retirement costs for the Units whenever they are retired, whether at the end of their useful lives or earlier. Accordingly, the timing of the retirement affects the present value of these costs, and the timing of rate impacts to customers, but not the nominal amount of the costs.

10. Economic Impact Study

10.1. Overview of the Economic Impact Study

Resource decisions made by utilities have impacts on the economies of the regions they serve. New energy infrastructure often brings employment and spending during construction and throughout operation. Retiring of existing power plants can have the opposite effect. This section of the Study addresses the estimated impacts of the retirement and decommissioning activities at the Wateree and Williams coal plants on local economies. It does not address the economic benefits of potential future replacement generation.

Retiring a coal plant has potential direct impacts on employees and local suppliers. There are also indirect impacts of coal retirement that may result from secondary effects, such as less local spending cycling through the economy (i.e., “multiplier effects”), as well as reductions in property taxes and other payments to government. The economic impacts of a plant closure vary broadly depending on the specific situation of the retiring plant and local community. For example, a broader and more economically diverse community may absorb lost economic activity from a plant retirement efficiently, while a smaller community may be more heavily reliant on the plant and less able to transition.

DESC has had success in the past in transitioning employees based upon changing conditions in the utility industry. Similar to previous coal plant retirement projects, such as the three units at Canadys Station, DESC will evaluate the capabilities of each employee to allow them to transfer into open jobs across DESC’s expanded footprint.

CRA evaluated the economic impacts of the retirements of Williams and Wateree at the county and state levels. This involved estimating the annual economic contributions of the plants when operating and assuming that these contributions would end with the retirement of the units. This is a conservative assumption (overestimates economic impact) because it does not account for any transitioning of current employees or suppliers finding other customers for their goods and services.

It should also be noted that the study examines the annual impacts of plant retirements and does not incorporate a duration related to the timing of early retirements evaluated in other sections of this Retirement Study.

DESC provided direct employment and compensation data, as well as plant expenditures by category and location, including property taxes to support this analysis. CRA evaluated indirect and “induced” impacts on the local and regional economies using the IMPLAN model, which is an industry standard approach for calculating the multiplier effects of economic activities, such as power plant closures. Separate from retirements, CRA also evaluated the economic impacts of decommissioning activities at the facilities that are expected to offset some of the lost economic activity due to early retirements.

10.2. Study Area Overview

To select the regional scope for the study, CRA focused on the counties that are likely to experience material economic impacts from retirements or decommissioning. This includes counties that are home to plant employees, those that have business that sell goods and services to the plants, and those that receive property tax revenues from the plants. The selection of counties to study was informed by the employment and expenditure data provided by DESC. **Figure 9** shows diagrams of the location of each plant and the immediate surrounding counties, and lists the counties studied for each plant when estimating economic impacts of retirements and decommissioning.[30] Economic impacts were also evaluated at the South Carolina state level.

Figure 9: Counties Impacted by Early Retirements of Wateree and Williams

<table>
<tr><th>Williams and Surrounding Counties</th><th>Wateree and Surrounding Counties</th></tr>
<tr><td>Located near Goose Creek, SC, just below the geographic center of Berkeley County, SC. Berkeley County is directly above the city of Charleston, the most populous metropolitan area in South Carolina. The area around the power plant is heavily industrial. The local workforce and the local supply chain extend to several nearby counties including Charleston County and Dorchester County.</td><td>Located near Eastover, SC, in the southeast corner of Richland County, which is the second most populous county in South Carolina and contains the state capital of Columbia. The plant is directly across the Wateree River from Sumter County, but farther by road (over 15 minutes to the county line). The plant is only about five miles from the much smaller Calhoun County which also provides connection to Orangeburg County.</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td><u>Counties Studied</u>
Berkeley, Charleston, Dorchester</td><td><u>Counties Studied</u>
Richland, Calhoun, Sumter, Orangeburg</td></tr>
</table>

To understand economic impacts at a regional level, it is helpful to understand the demographics and economic scale and diversity of impacted counties. All else equal, counties that are large and economically diverse are less likely to have noticeable impacts from a plant closure and may be more likely to successfully absorb any lost employment, business activity, or tax revenues. **Table 25** provides some key demographic indicators for each of the studied

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30 While the majority of local impacts stay within proximate counties to the plants, a county does not need to be near the plant to have a material impact. For example, Wateree sources limestone from Berkeley County, which is located several counties away.

counties. Williams is in a more populated and higher income region than Wateree. For reference, the U.S. national average poverty rate in 2020 was 11.4% [31].

Table 25: Study Area Demographic Data, 2019 [32]

County	Total Population	Number of Households	Median HH Income	Mean HH Income	Percent Under Poverty Line
Berkeley	229,861	80,640	$69,400	$88,200	10.7%
Charleston	408,235	165,568	$71,500	$104,300	11.2%
Dorchester	161,540	64,608	$68,200	$82,700	9.1%
Richland	416,147	153,484	$52,300	$76,300	16.6%
Calhoun	14,119	6,179	$46,300	$61,200	20.8%
Sumter	105,556	44,105	$51,000	$61,200	17.4%
Orangeburg	84,223	32,129	$37,700	$52,700	27.5%

Table 26 shows several key economic indicators for each of the counties studied. Regional Gross Domestic Product ("GDP") is the total value of all goods and services produced in the county and is a good metric for comparing the economic size of different regions. County tax revenues were sourced from county-level reports.

[31] US Census Bureau, *Income and Poverty in the United States: 2020*, by Emily A. Shrider, Melissa Kollar, Frances Chen, and Jessica Semega, P60-273, 2021.

[32] US Census Bureau, *Income and Poverty in the United States: 2020*, by Emily A. Shrider, Melissa Kollar, Frances Chen, and Jessica Semega, P60-273, 2021.

Table 26: Study Area Economic Data, 2019/2020 [33]

County	Employment	Regional GDP ($ billion)	County Revenues ($ million)
Berkeley	106,919	$8.2	$330 [34]
Charleston	210,904	$33.4	$560 [35]
Dorchester	80,282	$4.0	$61 [36]
Richland	192,235	$26.7	$394 [37]
Calhoun	6,250	$0.7	$21 [38]
Sumter	43,196	$4.6	$90 [39]
Orangeburg	32,667	$3.2	$84 [40]

10.3. Data and Methodology

Forecasts of economic impacts of electric generating plant closures can vary greatly depending on the types of impacts studied and the methodologies employed. There are multiple methods and levels of rigor to assessing impacts that may lead to divergent views about the severity of impacts and solutions for mitigation. In general, the best method for estimating impacts relies on actual data from the operations of the plant, including its workforce and supply chain details, and employ credible models for estimating indirect impacts. At a high level, this is the method employed in this study.

The data for this study was sourced directly from DESC in response to CRA-provided data requests. The following is a list of the data obtained by CRA:

- Direct workforce details, including payroll and locations (county) for all direct workers;
- Categorized expenditures on contractors, including locations of service providers;
- Categorized expenditures on materials and goods, including locations of suppliers;

[33] Total Population and employment data from the US Census, regional GDP values from the Bureau of Economic Analysis, in 2019 dollars.

[34] Berkeley County South Carolina, *Financial Statements with Independent Auditor's Report Year Ended June 30, 2020*.

[35] County of Charleston South Carolina, *Approved Budget For Fiscal Year 2021*.

[36] Dorchester County South Carolina, *Comprehensive Annual Financial Report For the Fiscal Year Ended June 30, 2020*.

[37] Richland County Government, *A comprehensive annual financial report for the fiscal year ended June 30, 2020*.

[38] Calhoun County, South Carolina, *Annual Financial Report for The Fiscal Year Ended June 30, 2020*.

[39] Sumter County South Carolina, *Basic Financial Statements June 30, 2020*.

[40] County of Orangeburg, South Carolina, *Basic Financial Statements and Supplementary Information June 30, 2020*.

- Property taxes;
- Other data relevant to economic impacts of the plants; and
- Decommissioning cost estimates, by category.

While much of the data is confidential, **Table 27** summarizes several data key to estimating economic impacts. They are provided for the "study area" for each plant, as defined in the previous section. The employment figures include direct jobs of employees that reside in several counties not included in the study area. Of these counties, Kershaw (12 jobs), Lexington (13 jobs), and Colleton (6 jobs) are the only counties in which more than two employees reside.

Table 27: Summary of DESC-provided Employment and Expenditure Data (# of employees, $million)

Plant	Direct Employment	Direct Income	Supply Chain (Total / Study Area)	Property Taxes [41]	Decommissioning Cost
Williams	72	$5.6	$121.2 / $26.6	~$4.5	$12.1
Wateree	80	$6.3	$96.4 / $31.3	~$8.5	$13.7

While the data provided by DESC is informative on the scale of impacts, to get a full understanding of overall economic impact, CRA conducted an analysis of direct, indirect, and induced economic impacts across the regional economies. These different types of impacts are described below:

- Direct – The direct impacts of an operating coal plant are the employees that are assigned to the plant, mostly on-site, and their income and benefits.
- Indirect – The main source of indirect impacts for an operating coal plant are the goods and services purchased to support fuel, operations, and maintenance activities. Indirect impacts can include multiple levels of the supply chain, such as when a locally sourced manufactured product was made with locally sourced materials. The indirect impacts of a coal plant are largest when the fuel is sourced from within the region, which is not the case for Williams or Wateree.
- Induced – Payments to direct employees and to indirect employees are recycled in the regional economy through spending of income. These benefits are considered the "induced" impacts. They also include the impact of property tax payments, which result in government spending in the counties in which the plants are located.

Direct impacts and property taxes were provided by DESC. Indirect and induced impacts were calculated by CRA using the IMPLAN model. The IMPLAN model is an input-output model, which is an industry standard approach for calculating the multiplier effects of economic activities, such as power plant closures. The model provides estimates of indirect and induced impacts of changes to regional spending or employment. CRA ran county level analyses using a Multi-Region Input-Output ("MRIO") setting. The MRIO accounts for how activity in one

[41] Property taxes are paid to Berkeley County (Williams) and Richland County (Wateree).

region can impact activity in neighboring regions, thus it is more inclusive of impacts than individual county models.

10.4. Key Findings

This section presents the results of the economic impact modeling and CRA analysis. The results are provided in four categories: employment, labor income, value added, and output, as described below.

Employment

The employment associated with the plants is provided in Full-Time Equivalents ("FTE"). An FTE represents the equivalent of one individual working 40 hours per week for one full year. It could also represent two individuals working a half-year, potentially less than one individual's year if that employee is working significant overtime. Therefore, FTEs can be seen as a rough proxy for headcount and are not exactly the same as "jobs." They are referred to as jobs herein, as is common in these studies.

The direct employment impacts of a plant closure are the impacts most commonly mitigated by plant owners. They can also be temporary as employees find other opportunities or choose retirement. The indirect and induced employment impacts are also not directly translatable to "lost jobs." Some supply chain jobs may indeed be lost, such as those at a supplier that only sells a specialized good to the plant as its sole customer. Other jobs can be redirected at other economic activities, possibly reducing income but not resulting in job loss. None of these mitigating factors were evaluated in this analysis. Therefore, the reported employment impacts likely overestimate the actual employment impacts of plant closures.

Labor Income

The reported labor income represents wages and benefits paid to direct employees and to the jobs reported along the supply chain (indirect) and elsewhere in the economy (induced). Income per employee is generally highest for direct employment, which includes skilled labor, and lowest for induced, which includes significant shares of less-skilled service jobs.

Value Added

A proxy for GDP impact. It can be defined as the total market value of all final goods and services produced within a region. It represents the wealth created by a local economic activity.

Output

Output represents all economic activity associated with the plants in the study area, including all transactions of goods and services in the area and all income. Because some goods may be transacted multiple times (as "intermediate" and "final" goods), the output value includes some double counting and is therefore less useful than the value added metric.

Results are provided at the county level and the South Carolina state aggregate level for each plant. Only one county, Berkeley County, shows up as having material economic impacts from both plant retirements, though the impacts from the Wateree closure are much smaller and entirely caused by limestone purchases.

10.4.1. Williams Economic Impacts

The Williams plant is located near the geographic center of Berkeley County and the economic impacts of early retirement of the Williams unit are highest in this county. The plant also purchases a significant share of its goods and services from Dorchester County (9% of total plant expenditures, or 47% of the expenditures that are made within the study area), and there are significant indirect and induced impacts in this county. Charleston County is home to less than 10% of the employees and receives about half of the supply chain impacts of each of the other two counties in the study area. The contributions to counties in South Carolina outside the study area are minimal.

Employment

The highest level of direct employment is located in Berkeley County (32 jobs), where 44% of plant employees reside, followed by Dorchester (18 jobs). The highest level of indirect employment impacts is in Dorchester County (67 jobs) due to supply chain employment, followed by Berkeley County (51 jobs). Induced employment is also greatest in Berkeley County (38 jobs), driven by government spending of property taxes. The employment impacts of the Williams plant are provided in **Table 28**.

Table 28: Williams Impacts: Employment (FTEs)

	Direct	Indirect	Induced	Total	*Share of Regional GDP (%)*
Berkeley County	32	51	38	121	*0.11%*
Dorchester County	18	67	15	101	*0.13%*
Charleston County	7	30	15	51	*0.02%*
Other SC	15	3	4	22	
Total SC	**72**	**152**	**72**	**296**	***0.01%***

Labor Income

As expected, the distribution of labor income is nearly identical to the distribution of employment. The labor income impacts of the Williams plant are provided in **Table 29**.

Table 29: Williams Impacts: Labor Income ($ millions)

	Direct	Indirect	Induced	Total
Berkeley County	$2.4	$2.8	$1.8	$7.0
Dorchester County	$1.4	$3.7	$0.5	$5.6
Charleston County	$0.6	$2.0	$0.7	$3.3
Other SC	$1.2	$0.2	$0.1	$1.5
Total SC	**$5.6**	**$8.6**	**$3.1**	**$17.4**

Value Added

The distribution of value added impacts is similar to the distribution of employment impacts. The value added impacts of the Williams plant are provided in **Table 30**. This table also reports the total value added impacts as a percentage of the county or state's GDP in 2020.

Table 30: Williams Impacts: Value Added ($ millions)

	Direct	Indirect	In-duced	Total	*Share of Regional GDP (%)*
Berkeley County	$2.4	$4.1	$3.2	$9.8	*0.12%*
Dorchester County	$1.4	$5.4	$1.1	$7.9	*0.20%*
Charleston County	$0.6	$2.7	$1.3	$4.7	*0.01%*
Other SC	$1.2	$0.2	$0.3	$1.7	
Total SC	**$5.6**	**$12.5**	**$5.9**	**$24.0**	***0.01%***

Output

The distribution of output impacts is nearly identical to the distribution of value added impacts. Output impacts are about double the value added impacts for both indirect and induced impacts, suggesting significant amounts of intermediate goods within the affected counties. The output impacts of the Williams plant are provided in **Table 31**.

Table 31: Williams Impacts: Output ($ millions)

	Direct	Indirect	Induced	Total
Berkeley County	$2.4	$8.3	$6.4	$17.1
Dorchester County	$1.4	$11.2	$2.0	$14.6
Charleston County	$0.6	$4.9	$2.3	$7.8
Other SC	$1.2	$0.5	$0.5	$2.2
Total SC	**$5.6**	**$24.9**	**$11.1**	**$41.6**

Property Taxes

Williams pays about $4.5 million per year in property taxes to Berkeley County. The impacts of these property taxes are included in the above tables as induced impacts. While the payments represent a significant share of the county's overall property tax receipts (over 10%), they represent only about 1.4% of total county revenues.

Decommissioning

The economic impacts of decommissioning activities are not included in the impacts above. The decommissioning impacts can be seen as offsetting a portion of the impacts from plant closures. DESC has not developed a detailed estimate of decommissioning costs for the Williams plant. It estimated a cost of approximately $12 million based on the size of Williams and DESC's recent experience with other coal plant decommissioning. The main categories of economic activity that benefit from decommissioning are construction, waste removal, and environmental services. The counties in the study area provide a share of these services. **Table 32** presents the total impacts of decommissioning activities in the study area (Berkeley, Charleston, and Dorchester Counties combined).

Table 32: Economic Impacts of Decommissioning Williams, Total Study Area

	Employment (FTE)	Labor Income ($ million)	Value Added ($ million)	Output ($ million)
Direct	36	$2.3	$3.4	$5.8
Indirect	6	$0.5	$0.8	$1.6
Induced	16	$0.4	$0.8	$1.4
Total	**36**	**$3.2**	**$5.1**	**$8.8**

10.4.2. Wateree Economic Impacts

Wateree is located in the Southeast corner of Richland County and the economic impacts of early retirement of Wateree are highest in this county. The direct employment of Wateree is more geographically dispersed than for Williams, leading to a wider distribution of direct impacts. The contributions to counties in South Carolina outside the study area are driven by employees that live in a few surrounding counties.

Employment

The highest level of direct employment is located in Richland County (15 jobs), followed by Calhoun County (13 jobs). The highest level of indirect employment is located in Richland County (71 jobs), followed by Sumter County (25 jobs) and Orangeburg County (24 jobs). Induced employment is also greatest in Richland County (73 jobs), driven by government spending of property taxes. The employment impacts of Wateree are provided in **Table 33**.

Table 33: Wateree Impacts: Employment (FTEs)

	Direct	Indirect	Induced	Total	*Share of Regional GDP (%)*
Richland County	15	71	73	159	0.08%
Sumter County	8	25	7	41	0.09%
Orangeburg County	11	24	6	40	0.12%
Calhoun County	13	17	2	32	0.52%
Berkeley County	0	9	1	10	0.01%
Other SC	33	2	8	42	
Total SC	**80**	**148**	**97**	**325**	**0.01%**

Labor Income

As expected, the distribution of labor income is nearly identical to the distribution of employment. The labor income impacts of Wateree are provided in **Table 34**.

Table 34: Wateree Impacts: Labor Income ($ millions)

	Direct	Indirect	Induced	Total
Richland County	$1.1	$5.1	$4.0	$10.2
Sumter County	$0.6	$1.4	$0.3	$2.2
Orangeburg County	$0.8	$0.9	$0.2	$1.9
Calhoun County	$1.1	$0.8	$0.0	$1.9
Berkeley County	$0.0	$0.5	$0.0	$0.6
Other SC	$2.8	$0.1	$0.3	$3.2
Total SC	**$6.3**	**$8.8**	**$4.9**	**$20.0**

Value Added

The distribution of value added impacts is also similar to the distribution of employment impacts. The value added impacts of Wateree are provided in **Table 35**. This table also reports the total value added impacts as a percentage of the county or state's GDP in 2020.

Table 35: Wateree Impacts: Value Added ($ millions)

	Direct	Indirect	Induced	Total	*Share of Regional GDP (%)*
Richland County	$1.1	$6.9	$6.6	$14.6	0.05%
Sumter County	$0.6	$1.8	$0.5	$2.9	0.06%
Orangeburg County	$0.8	$1.3	$0.4	$2.5	0.08%
Calhoun County	$1.1	$1.1	$0.1	$2.3	0.33%
Berkeley County	$0.0	$1.0	$0.1	$1.1	0.01%
Other SC	$2.8	$0.1	$0.6	$3.5	
Total SC	**$6.3**	**$12.2**	**$8.4**	**$26.9**	**0.01%**

Output

The distribution of output impacts is nearly identical to the distribution of value added impacts. Output impacts are about double the value added impacts for both indirect and induced impacts, suggesting significant amounts of intermediate goods within the affected counties. The output impacts of Wateree are provided in **Table 36**.

Table 36: Wateree Impacts: Output ($ millions)

	Direct	Indirect	Induced	Total
Richland County	$1.1	$13.0	$12.4	$26.4
Sumter County	$0.6	$3.6	$1.0	$5.2
Orangeburg County	$0.8	$3.0	$0.7	$4.5
Calhoun County	$1.1	$2.4	$0.3	$3.8
Berkeley County	$0.0	$2.1	$0.2	$2.3
Other SC	$2.8	$0.3	$1.0	$4.1
Total SC	**$6.3**	**$24.5**	**$15.5**	**$46.2**

Property Taxes

Wateree pays about $8.6 million per year in property taxes to Richland County.[42] The impacts of these property taxes are included in the above tables as induced impacts. The property taxes represent about 5% of Richland's overall property tax receipts but only about 2.2% of total county revenues.

Decommissioning

The economic impacts of decommissioning activities are not included in the impacts above. The decommissioning impacts can be seen as offsetting a portion of the impacts from plant closures. DESC has not developed a detailed estimate of decommissioning costs for Wateree. It estimated a cost of approximately $13 million based on the size of Wateree and DESC's recent experience with other coal plant decommissioning. The main categories of economic activity that benefit from decommissioning are construction, waste removal, and environmental services. The counties in the study area provide a share of these services. **Table 37** presents the total impacts of decommissioning activities in the study area (Richland, Calhoun, Orangeburg and Sumter Counties combined).

[42] Property tax estimates for Wateree are not individually reported and are therefore a DESC estimate.

Table 37: Economic Impacts of Decommissioning Wateree, Total Study Area

	Employment (FTE)	Labor Income ($ million)	Value Added ($ million)	Output ($ million)
Direct	39	2.4	3.9	6.6
Indirect	8	0.4	0.7	1.4
Induced	10	0.4	4.4	1.3
Total	**57**	**2.7**	**6.6**	**7.5**

10.4.3. Replacement Capacity

Because they do not account for any transitioning of current employees or suppliers finding other customers for their goods and services, the overall economic impacts of the Wateree and Williams retirements are likely overestimated. These estimates also do not account for any employees that may be retained by DESC and continue their employment in another role, as has been the case with the retirement of the former Canadys generating station. In addition, any future coal retirements will not occur in isolation. DESC would plan replacement capacity, and thus a complete accounting of the impacts would include an assessment of the economic impacts of investments in new capacity and supporting infrastructure. However, such capacity has not been designated at this time and has therefore not been studied.

In general, any replacement capacity would likely bring amplified benefits during construction. These benefits could even exceed the annual impacts of the coal plants during the construction period, though the geographic and sectoral distribution would likely be different. Annual impacts of ongoing operation could be similar but would more likely be lower due to less labor intensive operations associated with new plants and generating technologies.

The scale of impacts will be highly influenced by the types of generating capacity developed and the size and locations of each project. For context, the economic impacts of natural gas plants and solar plants are discussed briefly.

Natural Gas

While a single natural gas combined cycle plant can be similar in size to the coal plants studied, the impacts could be quite different. First, there would be significantly higher impact during construction, which could also include the construction of supporting natural gas infrastructure. Once the plant is operating, it would likely have a lower impact per MW as it would be expected to require less maintenance and be generally less labor intensive to operate.

The US Department of Energy ("DOE") manages an economic impact assessment model based on IMPLAN data that provides estimates of the economic impacts of new gas plants.[43] The following are the estimated impacts of a generic 700 MW natural gas plant built in South Carolina, with the study area being the entire state (though a large share of these jobs would be local):

- Construction Phase:
  - 709 direct jobs and nearly 2,000 total jobs over the construction period of about 3 years

[43] JEDI Natural Gas Model, DOE National Renewable Energy Laboratory (NREL).

    - $215 million in total value added
- Operating Phase:
    - 35 direct jobs and 100 total jobs
    - $8.3 million in annual value added (GDP impact)

Solar

On a per MW basis, solar construction can bring more jobs than many other resource types, though over a briefer construction period. Operating solar plants may also create a significant number of ongoing jobs on a per MW basis. The DOE does not maintain a model for solar development, but there are recent studies and company announcements that can be informative. The following table is a collection of announced job estimates for solar projects.

Table 38: Employment Impacts of Example Solar Projects

				Construction Period		Operating Period	
Project	**State**	**Capacity (MW)**	**Year Online**	**Direct Jobs**	**Jobs per MW**	**Ongoing Jobs (per year)**	**Jobs per MW**
Mercer County Solar	KY	175	2021	300	*1.7*	5	0.0
Chicot Solar	AR	100	2020	150	*1.5*		
Searcy Solar Project	AR	100	2022	200	*2.0*	2.5	0.03
Lone Oak Solar	IN	120	2023	150	*1.3*	2	0.02
Dragonfly Solar	VA	80	2020	150	*1.9*	4	0.1
Greenwood Solar	MS	100	2022	350	*3.5*		
Total		***675***		***1,300***	***1.9***	***20.3***	

As the bottom row of the above table shows, a solar facility of 675 MW would be expected to bring 1,300 direct jobs and about 20 ongoing jobs. It should be noted that the direct jobs estimate is likely in many cases would be less than FTEs since construction can take well under a year.

These examples are provided as indicative estimates. Once replacement resources have been selected by DESC, a more accurate estimate of the economic impacts associated with these replacements may be conducted.

11. Conclusion

This Study, along with the TIA, represent the first step in a regulatory, permitting, procurement and construction program to allow DESC to retire Wateree and Williams as early as possible in keeping with safe, reliable and affordable service. DESC's goal is to complete that process in a little more than eight years, which is an ambitious target.

1. A primary conclusion derived from this Study is that retiring Wateree at the end of 2028 appears to be feasible and under most market conditions could reduce both CO_2 emissions and costs to customers. Part of the benefit of retiring Wateree at this date is that it allows DESC to avoid the cost of complying with the current ELG rule requirements for FGD wastewater at Wateree. But retiring Wateree on this accelerated schedule subjects the system and its customers to risks and uncertainties concerning replacement capacity. Avoiding ELG compliance creates the risk that Wateree would have to be retired from service for environmental reasons even if replacement capacity is not yet in place.
2. Considering the complexity of siting replacement capacity and fuel supply for Williams, it is not reasonably feasible to retire that unit before 2030. This conclusion requires DESC to evaluate complying with the current ELG requirements at Williams.
3. Setting 2030 as the earliest feasible retirement date for Williams means adopting a schedule that includes little if any buffer to accommodate regulatory or construction delays. The 2030 date represents a "best case" planning goal that is subject to much risk and uncertainty. It is important that DESC monitor, review and revise this schedule as retirement planning continues.
4. Capturing the CO_2 benefits from retiring Williams early will entail slight additional cost to customers under most Market Scenarios. If there are delays in the critical paths for replacement generation, the early retirement of Williams could expose customers to higher costs and risks.

The conclusions of Study will guide future retirement planning and IRP proceedings. They will be subject to on-going review and modification as additional information and analysis becomes available.

The next major step in that eight-year process will be the completion of the 2023 IRP and the identification of preferred generation replacement options and retirement schedules for Wateree and Williams. DESC will do this in consultation with Stakeholders and present a thorough review of the data and analysis underlying its preferred plan in the 2023 IRP proceeding. The completion of that IRP will initiate a multi-part regulatory, planning, and procurement process to complete this process.

Appendix

Appendix A - Glossary of Terms

Abbreviation	Name
AACE	Association for the Advancement of Cost Estimating
AEO	Annual Energy Outlook
AGC	Automatic Generation Control
BAT	Best Available Technology
BATW	Bottom Ash Transport Water
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
CAGR	Compound Annual Growth Rate
CC	Combined Cycle Generation Plant
CC 1 x 1	A combined cycle gas-fired generating station with a one combustion turbine and one heat recovery turbine
CT	Simple Cycle Aeroderivative Combustion Turbine-Generator
CO_2	Carbon Dioxide
CRA	Charles River Associates
DESC	Dominion Energy South Carolina
DEV	Dominion Energy Virginia
DHEC	South Carolina Department of Health and Environmental Control
DSM	Demand Side Management
DMV	South Carolina Department of Motor Vehicles
DOE	United States Department of Energy

EIA	Energy Information Administration
EE	Energy Efficiency
ELG	United Stated Environmental Protection Agency's 2020 Effluent Limitations Guidelines
EPA	Environmental Protection Agency
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FTE	Full-Time Equivalents
GDP	Gross Domestic Product
GHG	Greenhouse Gas
HVAC	Heating, Ventilation, and Air Conditioning
ICEV	Internal Combustion Engine Vehicle
IHS	IHS Markit, an information services company providing market data and forecasts
IMPLAN	A company providing economic modeling software
IRP	Integrated Resource Plan
kW	Kilowatt
kWh	Kilowatt Hour
LNPV	Levelized Net Present Value
MMBtu	Metric Million British Thermal Unit
MRIO	Multi-Region Input-Output
MW	Megawatt
NERC	National Electric Reliability Council
NREL	National Renewable Energy Laboratory

NYMEX	New York Mercantile Exchange
O&M	Operations and Maintenance
ORS	South Carolina Office of Regulatory Staff
PHEV	Plug-In Electric Vehicle
PLEXOS	A resource optimization software provided by Energy Exemplar Pty LTD
PPA	Power Purchase Agreement
PV	Photovoltaics
RFP	Request For Proposal
SCPSA	South Carolina Public Service Authority
SOCO	Southern Company
TIA	Transmission Impact Analysis
VIP	Voluntary Incentive Program

Appendix B - Commission Orders and Requirements

Order No. 2018-804, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E

SCE&G Commitment to RFP Process Regarding Natural Gas Transmission Capacity

The Joint Applicants entered into a settlement with Transco that provides that following the closing of the Merger, SCE&G will not contract with an interstate pipeline for natural gas transmission capacity of 100,000 dekatherms per day or more unless or until it has issued a request for proposals to obtain such capacity and considers the proposals in good faith. SCE&G will file confidential reports with the Commission within thirty days of the conclusion of this process. Moreover, such an arrangement must be with the least cost provider of such capacity, unless the Commission has otherwise approved the contract. (p. 105)

Order No. 2020-832, Docket No. 2019-226-E

It is reasonable for the Commission to require DESC to perform a comprehensive coal retirement analysis to inform development of its 2022 IRP Update and its 2023 IRP and to solicit parties' recommendations on guidelines for performing this analysis through the ongoing IRP Stakeholder Process. Upon completion of the coal retirement study – and targeting the 2023 IRP – DESC shall begin modeling coal retirement as an option in the various scenarios. (p. 17)

The Commission also agrees with the recommendation of ORS Witnesses Sandonato and Hayet, SBA Witness Sercy and Sierra Club Witness Stenclik that a retirement analysis must be completed as soon as possible. While ELG costs themselves are not at issue in this IRP, these costs must be included in any retirement analysis conducted by the Company, and a retirement analysis must be conducted prior to making any decisions regarding whether to retrofit the Williams and Wateree units to comply with the ELG rule. In order for the Company to meet the December 31, 2025 deadline to retrofit Williams and Wateree, the Commission is opening a new docket to assess the retirement and replacement of the Company's coal plants. This proceeding will evaluate the reliability risks and environmental costs of continued operation of the coal plants as well as options, informed by resource bids, to replace legacy coal technology with state-of-the-art clean energy. DESC is required to perform a comprehensive coal retirement analysis to inform development of its 2022 IRP Update, and to solicit parties' recommendations on guidelines for performing this analysis and approve a set of guidelines prior to DESC's 2022 IRP Update development process via the ongoing IRP Stakeholder Process. (p. 40)

Since the Company's exposure to carbon pricing is inextricably linked with its use of coal generation, The Commission finds it appropriate for the Company to target the 2023 IRP to begin showing coal retirement as another option upon the completion of their coal retirement study. (p. 71)

DESC, in coordination with ORS, shall establish an ongoing IRP Stakeholder Process for the purpose of considering, and inviting stakeholder input and review on, certain potentially complex changes to DESC's IRP development methodology, inputs and assumptions. The IRP Stakeholder Process shall initially consider the following issues: … c. Comprehensive retirement analysis of DESC coal plants… (p. 91-92)

Order No. 2021-418, Docket No. 2021-192-E

The revisions to the DESC 2020 IRP previously ordered by the Commission resulted in Resource Plan 8 being selected by DESC as the "preferred portfolio" to lessen ratepayer impact, promote reliability, incorporate renewable energy, reduce carbon dioxide emissions, and considered the least risky of the resource plans. RP 8 also re-tires the Wateree and Williams coal plants in 2028 and converts the Cope coal plant to natural gas in 2030. I move that the Commission open a DESC Coal Retirement Docket so that the company and the parties can advise the Commission on an appropriate procedural schedule along with any statutory or regulatory deadlines that might need to be addressed. I further move that the Commission direct the Clerk's Office to issue a notice for intervention and comment from all interested parties and Stakeholders.

Order No. 2021-722, Docket No. 2021-192-E

I move that the Commission grant the Joint Motion Requesting an Amended Procedural Schedule and that the procedural dates be modified and established as follows:

- All Parties' Direct Testimony and Exhibits Due May 16, 2022
- All Parties' Responsive Testimony and Exhibits will be due June 6, 2022
- Hearing on the matter will be scheduled on or after June 30, 2022.

So move.

Order No. 2022-305, Docket No. 2021-192-E

I move that the Commission clarify that the Coal Retirement Docket as established in Order Number 2021-418 was established to develop a procedural schedule including the data, methodologies, analysis and next steps for considering coal plant retirement within the framework of future IRPs via the 2020 IRP Docket 2019-226-E and Order No. 2020-832, including any statutory or regulatory deadlines that may need to be addressed. I will note that, this is not a docket for making decisions regarding the retirement of coal plants. As such, I move that we retitle this docket "The Coal Plants Retirement Study Docket." I further move that the Commission adopt the following modified procedural schedule to allow the Intervenors and the Office of Regulatory Staff to adequately respond to the Coal Plants Retirement Study and other related studies that will accompany Dominion's filings:

- DESC Files Coal Plants Retirement Study exhibits and comments by May 16, 2022 (this was a previously established pre-filing deadline)
- Intervenors and Office of Regulatory Staff file comments by June 27, 2022
- DESC may file reply comments by July 18, 2022
- Intervenors and Office of Regulatory Staff may file reply comments by August 1, 2022

This allows all parties the opportunity to provide comments regarding the proposed study including its data, methodologies, analysis and next steps. Finally, I move that we hold in abeyance the hearings currently scheduled for June 30, July 1, and July 5, 2022.

Appendix C - Summary of Stakeholder Feedback

Stakeholder Feedback on The Retirement Study From IRP Advisory Group Session II and DESC Responses

Stakeholder Comments	Response / Action Taken
DESC did not model near-term solar and storage additions combined with early coal retirements. The preferred plan (RP8) retires coal units early, but these early retirements are replaced by natural gas units.	New Portfolio Concepts are included in the Session III Agenda.
DESC lacked transparency with its intentions to implement its CT plan and the IRP doesn't allow the PSC to evaluate the "impacts of new peaker(s)".	Discussion of the CT Plan in included in the Session III content.
A Stakeholder specifically noted that there is a "need to evaluate overall system reliability impacts" of early coal retirements, in addition to evaluating transmission impacts.	Retirement Analysis is on the agenda for Session III and Stakeholders will have an opportunity to provide additional detail on the reliability impacts that DESC should consider.
Stakeholders questioned the lengthy timeline of coal retirement studies. Additionally, they asked how the schedule aligns with the selection of an ELG plan for each coal plant and how DESC plans to avoid committing to unnecessary ELG upgrade costs.	• A Retirement Study involves the coordinated effort of multiple functions within DESC. Resource planning, transmission, generation planning, and environmental departments are all involved, each with substantial responsibilities. • DESC is required to make a regulatory filing regarding its ELG compliance plans by October 2021. DESC is undertaking the coal retirement studies prior to committing to ELG compliance project costs.
The TIA scenarios explicitly define the replacement resources to be studied under each scenario. What is the relationship between the TIA scenarios and future IRP scenarios, and will this analysis limit the resource options that DESC can consider in future IRPs?	The TIA is a preliminary analysis and the scenarios requested will not limit the options than can be considered in the IRP, rather they are designed to book-end the available options, including full replacement with market purchases as opposed to new units.
How come DESC is only considering Wateree as part of the TIA request, and when will DESC evaluate the other units on its system for early retirement?	DESC modified the TIA request in May to include both the early retirement of Williams and Wateree in the modeled scenarios.

Stakeholders requested the topic of 'Potential benefits of modeling a coal retirement securitization scenario to inform public policy considerations' be discussed in stakeholder session III.	Allowing securitization of coal retirement costs would require a legislative change and the purpose of this Advisory Group is to inform the approach and inputs to DESC's IRP.

Stakeholder Feedback on The Retirement Study From IRP Advisory Group Session III and DESC Responses

Stakeholder Comments	Response / Action Taken
A Stakeholder recommended a transparent workflow between the TIA and the IRP that provides a logical connection between TIA outputs and future IRP inputs: • Suggested that the optimization model select portfolios to meet system needs, while incorporating transmission costs specific to the resources. • Suggested that DESC provide written clarifications to the TIA request.	The TIA is an initial screening study used to book-end expected costs across a wide range of options, rather than explore in detail the cost of any one strategy. DESC will provide further details about how the costs estimates from the TIA will be used in the IRP analysis with Stakeholders as the process advances and results are available.
The same Stakeholder also requested that all Stakeholders be able to review the files the Transmission Group uses to respond to the TIA request.	The DESC Transmission Group will provide a report to the DESC IRP Team not the underlying model or input files. DESC will share elements of this report with interested Stakeholders subject to an NDA or confidentiality requirement.
• The five TIA Cases do not have a basis in economic selection or in identified reliability concerns. • Intervenors note that the substantive details of Case 5 are not described.	The TIA is an initial screening study used to book-end expected costs across a wide range of options, rather than explore in detail the cost of any one particular strategy. DESC believes the five cases selected will provide a reasonable indication of the magnitude and range of expected costs. The DESC Transmission Group can select from different sources of purchased power that best mitigate transmission needs.

TIA request should be amended to address the following: • Study retirement of coal units simultaneously and sequentially. Simultaneous retirement may be more economically optimal; a sequential approach increases the risk of needless stranded costs. • The TIA should not specify size and type of replacement generation. It should give deference to the Transmission Group to determine the smallest amount of generation needed to mitigate issues. • The Transmission Group should have flexibility to combine generation, transmission, storage, and load flexibility to resolve reliability concerns; combinations may be lower cost than generation alone.	• The five TIA scenarios include simultaneous and sequential early retirements. • The Transmission Group is not performing an explicit analysis to optimize the replacement of early retirements and requires specific information about what scenarios to consider in order to perform the study. • The Transmission Group is evaluating a combination of operational measures alongside transmission and generation mitigation options when evaluating the requirements to maintain system reliability.
DESC should consider solar and storage as a replacement options in the retirement study.	The TIA scenarios include early retirement and replacement with solar and energy storage resources, and these will be considered as candidates for the retirement study.

Stakeholder Feedback on The Retirement Study From IRP Advisory Group Session IV and DESC Responses

Stakeholder Comments	Response / Action Taken
Stakeholders commented that they understood that the retirement analysis would focus on determining the schedule of coal retirements and whether retirement “is feasible or not,” and would test for an economic benefit.	This is correct, the purpose of the Retirement Study is to understand the impacts of different early retirement options on the broader system and quantify the expected benefit or cost to customers.
Stakeholders commented that from a purely analytical standpoint, it makes the most sense to simply allow, as part of the coal retirement analysis, the capacity expansion model to retire assets as part of the core IRP modeling. Further, the coal retirement option should include other costs that may be avoided or incurred such as transmission upgrades, plant capex and maintenance, etc.	DESC’s planned approach in the Retirement Study and future IRPs is to allow PLEXOS to economically retire the Units in the manner described. The Retirement Study is intended to inform what those input values should be.

Stakeholders commented that they understood DESC to have suggested that the retirement analysis would be a simplified analysis that would not determine replacement resources for the coal retirements. Stakeholders noted that the question of whether it is economical to retire a unit is almost always answered in comparison to the cost of the replacement units.	The Retirement Study modeling will include economic selection of new replacement resources. When DESC discussed a limited analysis, this was a reference to the fact that the number of market scenarios and replacement options offered to the model would be more limited than those considered in a full IRP analysis, as discussed below in Section IV.
Stakeholders wanted more information about how DESC would model early retirements, and when they would have future opportunities to provide feedback on study inputs and review results.	DESC indicated that it would provide further information about the Retirement Study to Stakeholders and engage with them again in the fall to discuss inputs as the study progresses.
Stakeholders express a concern about the breadth of the TIA scenarios and suggested a 6th TIA scenario with a heavier emphasis on deployment of clean energy.	DESC indicated that it would consider running a 6th TIA case, but did not commit to adding a new case due to time constraints.
Stakeholders asked for the contact information of the DESC's Transmission Planning Group's counsel to inquire why the transmission modeling files cannot be shared. Stakeholders maintain that DESC must share the transmission modeling if it is to be used in the Stakeholder group or as evidence before the Commission.	DESC has provided the contact information requested and has already committed to sharing the report that will be provided by DESC's Transmission Planning Group to the IRP Stakeholder Group's interested Stakeholders.
Even though a "zero mitigation" TIA scenario would not demonstrate a reasonable operational outcome, Stakeholders believe that it would provide valuable information relating to the transmission constraints associated with coal retirements.	The DESC IRP team discussed this feedback with DESC's Transmission Planning Group. DESC's Transmission Planning Group responded that a "no mitigations" case was unrealistic. All retirement scenarios will require transmission upgrades to meet NERC TPL Reliability Standard criteria. A "do nothing" case won't comply with these mandatory reliability standards.

Stakeholder Feedback on The Retirement Study From IRP Advisory Group Session V and DESC Responses

Stakeholder Comments	Response / Action Taken
We recommend adding a scenario with coal retirements (isolation and joint) with no replacement to identify thermal and voltage violations and find mitigations, rather than develop scenarios prior.	The 5 TIA scenarios already consider isolated and joint retirements, and DESC will provide information to interested Stakeholders, under NDA, describing the resulting violations.
It may be prudent to develop a scenario that considers the potential ramifications of sustained inflation in gas and coal fuel prices and in new capital.	DESC is already considering a range of gas prices that will affect the cost of replacement units and has been instructed to use RFP informed cost data to inform new capital cost inputs.
We are uncertain how the PLEXOS retirement analysis will differ from analysis in the 2022 IRP Update. We suggest that the retirement study is a parallel and potentially redundant effort.	DESC is performing the Retirement Study under a separate proceeding from the 2022 IRP Update, for which no schedule has yet been set. DESC cannot wait for clarity on the 2022 IRP Update schedule prior to advancing the Retirement Study.
We agree that the proposed range of CO_2 prices are reasonable but natural gas prices are too low. We suggest current Henry Hub prices highlights a need to broaden the range of potential gas prices and increase base view, particularly in the near term.	Thank you for this feedback. DESC has captured the short-term increase in natural gas prices as part of the retirement study.
DESC's load forecast is too high. Recommend modeling lower load growth since forecasts are in part based on economic growth - pre-pandemic forecast may be optimistic.	DESC is using the 2022 base case view as the basis for the Retirement Study, this updated forecast includes the impacts of the pandemic.
We could not comment because the cost and performance assumptions were not in the presentation and we request these additional details.	Thank you for this feedback. DESC provided additional details following Session VI and looks forward to further Stakeholder feedback.
We suggest DESC use the latest 2021 NREL ATB for new resource cost and performance inputs.	DESC used the NREL 2021 ATB for new resource cost and performance estimates of new solar, storage, and solar + storage hybrid units in the Retirement Study. The cost and performance of new thermal units came from the company's internal "green sheet" estimates.

We recommend removing the low gas / high CO_2 scenario - there is no plausible scenario in which gas prices decline significantly from expected while CO_2 is priced at $35/ton without other limiting factors that would discourage increased utilization of gas.	DESC does not agree that this combination of factors is implicitly implausible. However, the case has been modified in response to Stakeholder feedback.
The CO_2 target sensitivity should be in line with DESC's corporate goals and avoid the use of offsets or other measures that would imply reductions.	DESC has not yet defined a plan to achieve CO_2 targets, and any future plan will serve the best interest of customers and may include use of offsets.
The purpose of the RA and its relation to future IRPs is poorly defined. Testing the economics of retirement under scenarios could be part of the next IRP. Stakeholders recognize that it can be useful to analyze in stages, but DESC has not articulated its rationale. Performing the retirement analysis separately may be a waste of time and resources, or the results may be misleading.	DESC is performing the Retirement Study under a separate proceeding from the 2022 IRP Update, for which no schedule has yet been set. DESC can't wait for clarity on the 2022 IRP Update schedule prior to advancing the Retirement Study.

Stakeholder Feedback on The Retirement Study From IRP Advisory Group Session VI and DESC Responses

Stakeholder Comments	Response / Action Taken
How and when will DESC evaluate alternative TIA scenarios? We would like to see results of TIA analysis that assumes some or all replacement resources are sited at Williams or within the Charleston load pocket more generally. Standalone battery storage resources could also be an effective mitigation for transmission upgrades.	DESC intends to request another analysis starting in Q3 2022. Input on the cases would be welcome and is included as a homework item. As in the previous TIA development, a limited number of cases will aid in completing the analysis in a timely manner.
DESC claimed that Williams ELG costs are assigned on 01/01/2025 and cannot be avoided. Please provide an explanation of the ELG compliance options, timeframes, and associated costs.	Thank you for this feedback. A discussion of the ELG compliance options, timeframe and costs will be included as part of the retirement study report.
How is DESC coordinating coal retirements, transmission upgrades, and natural gas pipeline considerations with Santee Cooper and other utilities in the region that are also proposing coal retirements and natural gas builds?	DESC coordinated with Santee Cooper as transmission reliability entities on the TIA analysis as required by NERC. Other non-reliability collaborations, if they occur, will be arms length.

Please see comments on the 2021 IRP Update which advises informed use of public data sources including the NREL ATB. Assuming DESC intends to use the same costs from the 2021 IRP Update, and if not to provide the opportunity to examine intended costs.	DESC used the NREL ATB 2021 “Advanced” case as the basis for the retirement study inputs for solar and storage resources. DESC will discuss future new technology cost inputs with Stakeholders through the Advisory Group process.
Has DESC tested out a carbon reduction constraint in PLEXOS as of yet and if so, is this limit a hard constraint?	No explicit CO_2 constraint has been modeled to date. However, the Reference Case scenario of the retirement study already achieves the level of emissions reductions in line with Dominion Energy’s 2035 corporate-wide target.
Without understanding how PLEXOS might treat a CO_2 limit, our recommendation would be for DESC to model an 85% reduction in carbon emissions by 2035, with possible adjustments to accommodate a reasonable retirement schedule for any affected gas units. If possible, we would prefer the model be given flexibility in the trajectory to achieve this target rather than imposing annual values.	The DESC target proposed by Stakeholders is well beyond what Dominion Energy has committed to as part of its corporate-wide target. DESC appreciates the Stakeholder’s suggestion of using a 2035 target and allowing flexibility rather and employing annual targets.
We recommend DESC consider at least two scenarios. The first would be an 80% reduction from 2005 levels in GHG emissions by 2030, which would put utilities on a pathway consistent with a 1.5°C future. The second scenario would include a 90% reduction from 2005 levels by 2035, which was deemed both technically and economically feasible in a report released by The Goldman School of Public Policy.	The DESC target proposed by Stakeholders is well beyond what Dominion Energy has committed to as part of its corporate-wide target and there is no other federal or state policy that would require the level of reductions proposed.
Stakeholders do not disagree that smaller units located closer to load centers will be more expensive than the 75MW solar options offered to PLEXOS. However, stakeholders are concerned that not modelling these smaller resources excludes the consideration of the potential benefits in this resource pathway. Would it be possible to assign an avoided transmission cost benefit to these resources using TIA results?	For the purpose of evaluating generic resources in the PLEXOS LT model, DESC believes the 75 MW solar options are sufficient. The TIA study completed to support the retirement study does not include information needed to determine the cost savings, if any, of smaller generic solar projects.
DESC will be using LT Plan to evaluate retirement of its coal units, is that right?	That’s right; PLEXOS LT Plan will evaluate the retirements and new resource candidates.

When will DESC be able to provide the PLEXOS files from the retirement analysis?	Actual PLEXOS files will only be provided to PLEXOS license holders with an NDA in the docket. These files will be provided when requested and when DESC determines the results are final. Also, Intervenor Licenses are only valid for the IRP docket. Notwithstanding these restrictions, the Company will provide modeling inputs and outputs to the parties
DESC will attach the $309 million upgrade cost from the TIA's Case 3 to the retirement of Williams and Wateree, correct? If so, can you provide a breakdown of these costs between the two units?	As noted in the TIA Report, many of the upgrade costs are associated with purchased power and specifically, the upgrade costs in Phase 1 of Case 1 are needed only to flow purchased energy on the DESC Transmission System. This means that no transmission upgrade costs, or almost no costs, are identified for the retirement of Wateree. In the case of a Wateree and Williams retirement, all costs are assigned to Williams. This is a reasonable assumption since most of these costs could be avoided if Williams was replaced at the same site or not retired.
To our knowledge Canadys was the site of a 490 MW coal generator, but most replacement resources evaluated at this location were larger than the previous coal plant (1057 MW in Case 3 and 534 MW in Case 4). It is unclear from the results how much of the network upgrade costs are attributed to the increased capacity sited at the location. An alternative scenario should evaluate a like replacement of the 490 MW plant to avoid additional network upgrades.	Thank you for this feedback. DESC intends to request another analysis starting in Q3 2022. Input on the cases would be welcome and is included as a homework item. As in the previous TIA development, a limited number of cases will aid in completing the analysis in a timely manner.
A scenario that explicitly evaluates the proposed Winyah coal retirement in neighboring Santee Cooper region would also be incorporated. There may be either increased transmission costs or potential cost savings associated with interregional transmission planning.	The TIA scenarios run already include the proposed Winyah coal retirement and necessary mitigations and it will be included in any future scenarios.

TIA provided some information on potential transmission planning criteria violations and upgrade cost estimates, but it was unclear how the dispatch of specific DESC resources was considered. Because these decisions can have a material effect on necessary upgrades, it would be beneficial to stakeholders to have a clear discussion on how this analysis was conducted.	The exact dispatch used was provided to intervenors who signed an NDA in the coal retirement docket. In general, solar was assumed to be off at time of winter peak. Other resources were dispatched in general economic order. Hagood CTs were dispatched in most cases, while Bushy Park was not. Running Bushy Park would have a small impact on the loading of the transmission lines into Charleston, but it is unlikely to change the overall conclusions of the TIA. Nonetheless, when a full System Impact Study is ultimately conducted, a full evaluation of the dispatch options versus transmission projects will be performed.
PLEXOS model has the ability to model an N-1 security constrained economic dispatch using a DC optimal power flow (DCOPF). This can be linked to use the same power flow network topology used in the TIA analysis. A nodal PLEXOS analysis can help determine the placement of replacement resources and operational considerations before downstream modeling in the AC Power Flow (ACPF) tools.	Thank you for the recommendation. DESC will investigate this proposal.

Stakeholder Feedback on The Retirement Study From IRP Advisory Group Session VII and DESC Responses

Stakeholder Comments	Response / Action Taken
It remains unclear why DESC is assuming Williams cannot retire by 12/31/2028 and avoid the ELG upgrade requirements. We request that in a future stakeholder session DESC clearly discuss the ELG compliance options available to both Williams and Wateree, and discuss any determinations the company has made regarding those options.	DESC will provide a schedule detailing the critical path and required duration of the replacement project. DESC will also provide the commitments, constraints and determinations for ELGs as presented in the Retirement Study.
While the Stakeholder Session VII provided some preliminary results for the portfolio LNPVs, it did not provide any information on selected candidate technologies for replacement. In the next stakeholder session, please provide this information, along with a discussion on why DESC believes each technology was selected (or not selected) by the model.	DESC provided the list of candidate resources in Session VI. A small number of specifications used in the actual PLEXOS retirement study have changed, these exact resource definitions will be provided to Stakeholders. Because of the nature of a resource optimization, it can be positively stated that the model chose each resource to meet the energy, demand, and reliability criteria at the lowest cost.

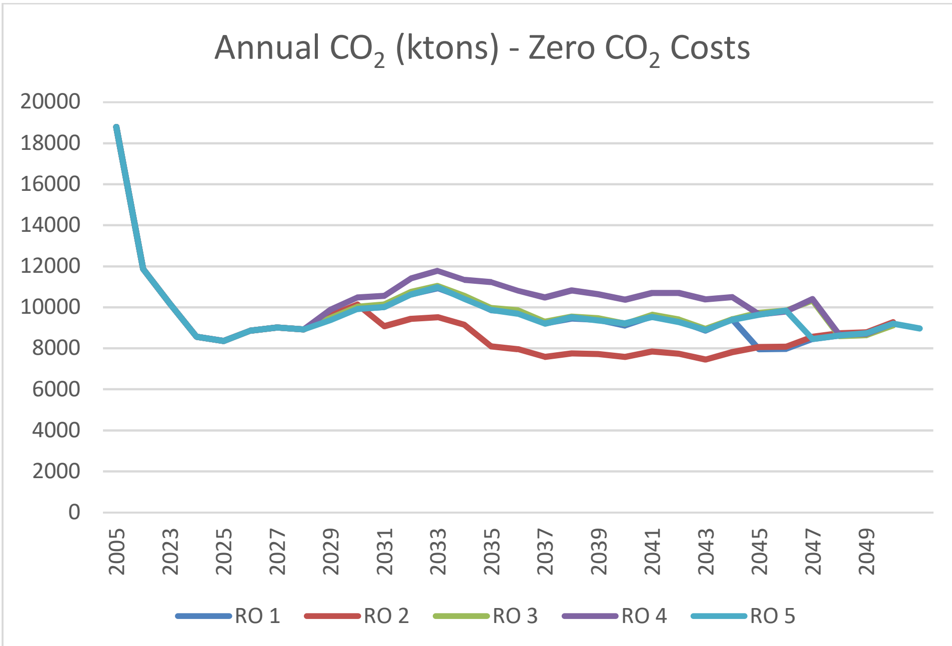
Stakeholders are seeking descriptions of model settings for the PLEXOS LT capacity expansion module. Of particular interest is the model horizon, any splits in the horizon, and how the model is handling chronology and week/day sampling.	In all models, LT Plan was run in a single 30-year step. Per written recommendation of Energy Exemplar, DESC found that run times improved and the model converged regularly using the global slicing blocks with five time slices per day, as recommended for systems with higher percentages of solar. This creates a mini load duration curve each day, does not maintain chronology within the day, has better results than a fitted solution when high levels of solar are included, and does maintain chronology daily, weekly and monthly.
We have some concerns about the manner in which solar and storage are being treated. Specifically, the ITC should be applied regardless of ownership and hybrid batteries should not be constrained to be charged from the paired solar resource for the lifetime of the asset, but rather follow the ITC rules that require renewable charging for only the first five years.	In the Retirement Study both Company-owned resources and PPAs include the benefit of the ITC. Expansion candidates are generic units and DESC will continue to evaluate paired resources as being charged by the solar component. DESC will model PPAs in configurations that are presented to the company through the RFP process.
DESC should include portfolios with full and partial replacement resources at or near Williams station. Because the Charleston area is a load pocket on the transmission system, retiring a large amount of generation in the area without local replacement is likely to be a large driver of the transmission upgrade costs.	DESC will request scenarios with full and/or partial replacement of resources at or near Williams station, as requested by Stakeholders, as part the next TIA study expected to commence in Q3 of 2022.

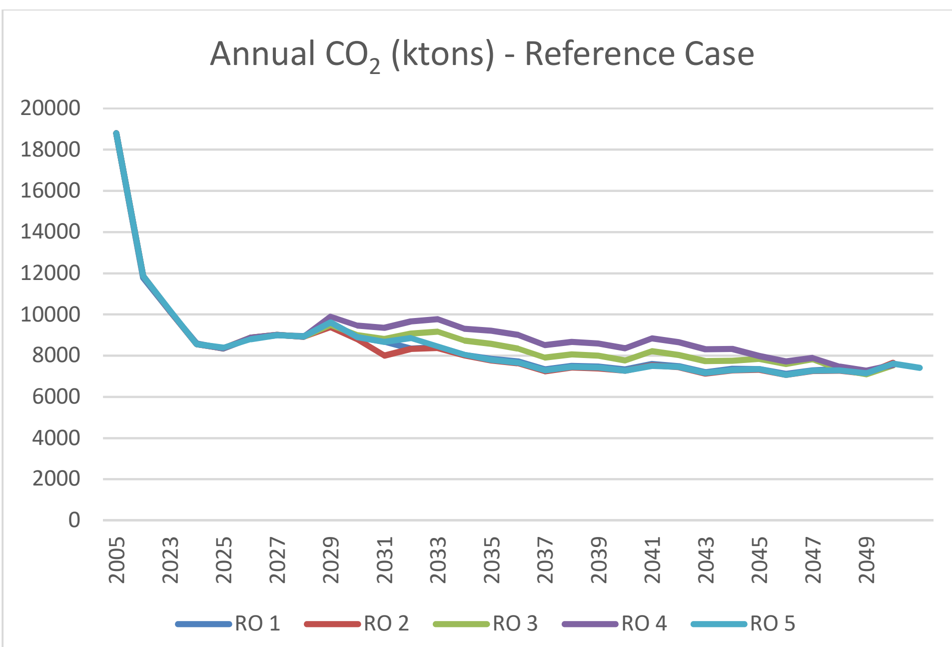
To our knowledge Canadys was the site of a 490 MW coal generator, but most replacement resources evaluated at this location were larger than the previous coal plant (1057 MW in Case 3 and 534 MW in Case 4). It is unclear from the results how much of the network upgrade costs are attributed to the increased capacity sited at the location. An alternative scenario should evaluate a like-for-like capacity replacement of the 490 MW plant to avoid additional network upgrades.	Case 4 of the original TIA already examined the installation of a similarly sized unit (534 MW) at the former Canadys site. The system has changed significantly over the last 10 years. While Canadys had 230 and 115 kV interconnection capability the conductors must be uprated and/or additional lines must be built to accommodate new generation at the site. There are no longer existing interconnection rights at the site. DESC is considering options to take advantage of the existing equipment to the maximum extent reasonably possible.
A scenario should explicitly evaluate the proposed Winyah coal retirement in neighboring Santee Cooper region. There may be either increased transmission costs or potential cost savings associated with interregional transmission planning.	Thank you for that insight. That is one of the reasons a joint study with Santee was undertaken. Together, the two companies make up the South Carolina Regional Transmission Planning regional planning entity. For this reason, and the highly integrated nature of the two systems, joint planning must continue to occur. The Winyah retirement was assumed to occur in the first five TIA cases that was performed by DESC.
The preliminary results of the retirement study presented to stakeholders do not comply with the Commission's order on the Company's 2020 IRP. The Company has decided that it is simply not feasible to avoid ELG costs at Williams, despite having requested a December 31, 2025 ELG compliance date to Williams. We have some serious concerns about the quality and validity of the TIA, including its ability to speak to the transmission upgrades that are universally necessary to facilitate retirement of this unit.	The Company has serious concerns about maintaining reliability in the greater Charleston area without the Williams plant. DESC has seen the importance of the unit in the day-to-day operation of the system, not just planning models. DESC must ensure that reliability of the grid in all instances including peak loads with loss of multiple transmission elements. The TIA and future studies are evaluating the upgrades needed to meet the Company's responsibilities under all conditions.
The absence of a baseline study for the TIA analysis raises the question of how many system reinforcements would be necessary or prudent independent of coal retirement.	The DESC system is assessed annually for the 10 year planning horizon. All reinforcements that were identified as part of that assessment by year-end 2020 were included as part of the of the base TIA cases.

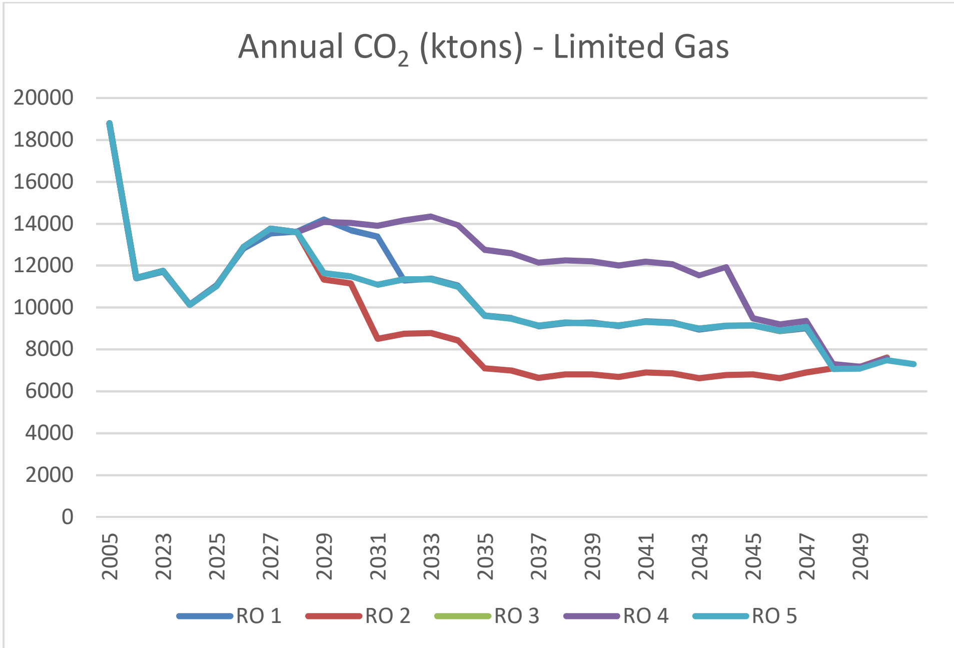
It would also be useful to explore how many of the minor violations could be mitigated with other NWA, such as dynamic rating, operate around, selective reinforcements, and other grid enhancing technologies.	The TIA was a preliminary assessment indicating the contingencies shown to be the most severe for each limiting element listed. Evaluation of many more contingencies that created overloads or high loading of transmission elements would be needed for op guides, etc. This all takes time and will ultimate be addressed in future System Impact studies. Winter ratings were included as part of the winter season studies. Dynamic ratings are a short-term operational tool. Operations will use dynamic ratings as appropriate facing often conditions worse than N-1-1 contingencies.
DESC should analyze generation options for which no (or minimal) amount of transmission reinforcements would be required.	DESC will consider evaluating the option to replace some of Williams existing generation with some form of on-site resources in a future TIA scenario.
We are generally supportive of using the NREL ATB Advanced Technology Cost Scenario for solar and battery storage resources, provided it is updated to the latest available version. However, it is unclear from DESC's stakeholder session material what the source will be for thermal resources.	As described in Stakeholder Session V and VI, the inputs for thermal units are sourced from the Company's "green sheets".
Given current macroeconomic conditions, inflationary pressure and supply chain constraints are likely across the industry in the short term. DESC should avoid applying any additional costs solely to renewable or storage resources. While these challenges have been a topic of concern across the industry, these disruptions will be true for conventional thermal technologies and transmission investment as well - including for replacement parts and plant upgrades.	DESC has a basis for the costs applied to all candidate resources, regardless of technology.
We recommend that DESC provide detailed heat rate modeling assumptions for all units at the next stakeholder session. In the case of the new ICT and CC generators, the Company's specific heat rate curve was not properly refit to the polynomial curve. To avoid this change – and use the Company's heat rate curve directly, the model's "Production object" setting for "Max Tranches" must be set to less than three so that the simulator used the marginal heat rate function provided in the input data verbatim.	DESC has corrected the issue and is specifying efficiency with an average heat rate curve.

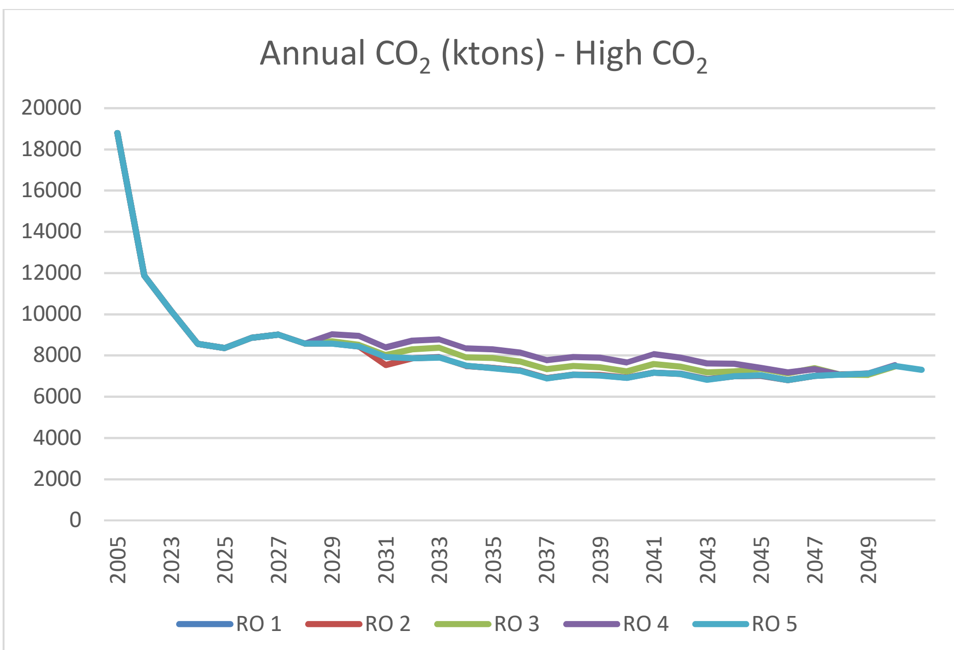
Similar to the proposed TIA scenario, we propose DESC evaluate a scenario that assumes an early retirement (12/31/2028 at the latest) for both Williams and Wateree. This is consistent with the 2021 IRP Update preferred portfolio RP8. In addition, this scenario should not include transmission upgrades for the Williams retirement, on the assumption that replacement resources are located at or near the Williams site.	DESC does not believe that the replacement generation needed to maintain system reliability can be brought online by 12/31/2028. This finding is supported by the Retirement Study.
While the DESC proposed scenario matrix includes base and high load forecasts, a low load forecast scenario is not evaluated. As a result, we recommend a scenario that assumes lower load growth.	The market scenarios included in the Retirement Study were developed in consultation with Stakeholders. A low load scenario is not expected to materially change the within 10 years, and DESC's intent was to focus on the most impactful scenarios.
We propose scenarios (both PLEXOS LT and ST) that assume coal retirements and no new gas resources are available. This will properly bookend the analysis to show the costs, benefits, emissions, and operations with a clean energy replacement portfolio.	DESC is open to exploring such a scenario in the 2022 IRP Update. The Company also intends to include new carbon-free options, such as nuclear SMRs, in future IRP studies.

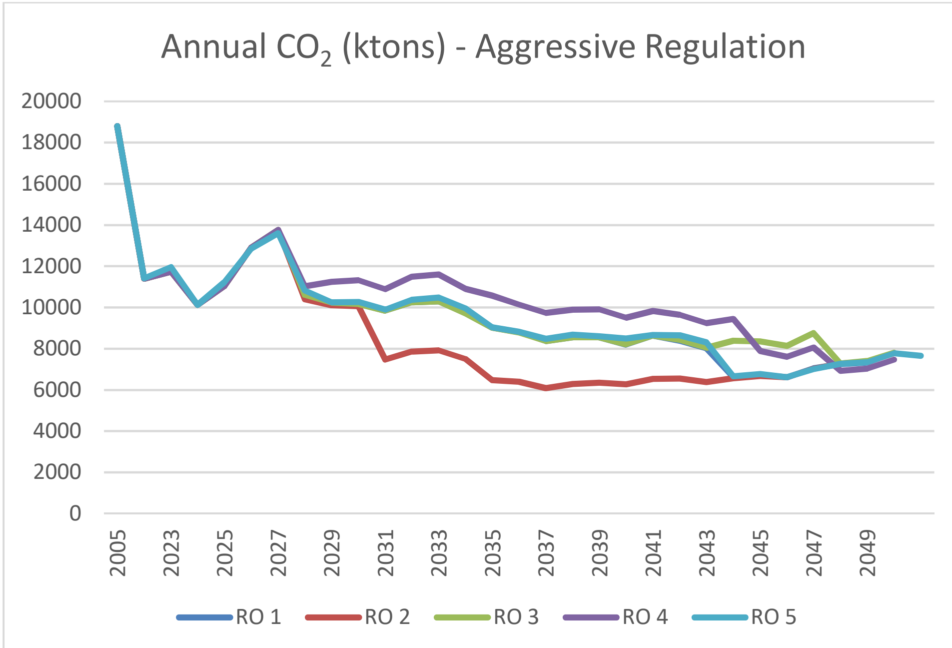
Appendix D – Annual Carbon Reductions by Market Scenario






Annual CO_2 (ktons) - Limited Gas
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
2005
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041
2043
2045
2047
2049
RO 1
RO 2
RO 3
RO 4
RO 5


Annual CO_2 (ktons) - High CO_2
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
2005
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041
2043
2045
2047
2049
RO 1
RO 2
RO 3
RO 4
RO 5


Annual CO_2 (ktons) - Aggressive Regulation
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
2005
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041
2043
2045
2047
2049
RO 1
RO 2
RO 3
RO 4
RO 5